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1.0 INTRODUCTION AND SUMMARY

1.1 PROJECT IDENTIFICATION

This Final Safety Analysis Report (FSAR) was originally submitted in support of the application of the Georgia Power Company (GPC), herein designated as the Applicant, for a facility operating license for the Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1) for power levels up to 2436 MWt under section 104(b) of the Atomic Energy Act of 1954, as amended, and the regulations of the Atomic Energy Commission (AEC) set forth in Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50). Pursuant to an application dated September 18, 1992, the NRC issued operating license amendments on March 17, 1997, effective March 22, 1997, designating Southern Nuclear Operating Company (SNC) as the exclusive operating licensee of HNP. SNC has no ownership interest in HNP.

The HNP-1 is located at a site near Baxley, Georgia. The operating license was issued on August 6, 1974, and commercial operation began December 31, 1975. The gross electrical output of HNP-1 was ~ 813 MWe, which corresponds to a net output of ~ 786 MWe. The HNP-1 facility operating license was revised to increase the maximum power level to 2763 MWt. The Technical Specifications (Appendix A to the operating license) were revised by Amendment No. 214. Renewed operating license No. DPR-57 for HNP-1 was granted by the NRC on January 15, 2002, in accordance with the provisions of 10 CFR 54. In Amendment No. 238 to the Technical Specifications, the HNP-1 operating license was revised to increase the maximum power level to 2804 MWt.

1.1.1 IDENTIFICATION AND QUALIFICATIONS OF CONTRACTORS

1.1.1.1 Applicant Licensee

See subsection 1.4.2 of the HNP-2-FSAR.

1.1.1.2 Architect Engineer

See subsection 1.4.3 of the HNP-2-FSAR.

1.1.1.3 Nuclear Steam Supply System Supplier

See subsection 1.4.4 of the HNP-2-FSAR.

1.1.1.4 Turbine-Generator Supplier

GE designed, fabricated, and delivered the HNP-1 turbine-generator, as well as provided technical assistance for installation and startup of this equipment. GE has a long history in the application of turbine-generators in nuclear power stations which extends back to the inception of nuclear facilities for the production of electrical power.

1.2 DEFINITIONS

The following definitions apply to the terms used in the FSAR:

A. Engineered Safeguard

An engineered safeguard performs design functions that are required actions (HNP-2-FSAR subsection 15C.2.3) to assure conformance with safety analysis event acceptance limits for accidents (HNP-2-FSAR subsection 15.1.5).

B. Nuclear System

The nuclear system generally includes those systems most closely associated with the reactor vessel which are designed to contain or be in communication with the water and steam coming from or going to the reactor core. The nuclear system includes the following:

- Reactor vessel.
- Reactor vessel internals.
- Reactor core.
- Main steam lines from the reactor vessel to the isolation valves outside the primary containment.
- Neutron monitoring system.
- Reactor recirculation system.
- Control rod drive system.
- Residual heat removal system.
- Reactor core isolation cooling system.
- Emergency core cooling system.
- Reactor water cleanup system.
- Feedwater system piping between the reactor vessel and the first valves outside the primary containment.
- Low-low set relief logic system.
- Pressure relief system.

C. Power Generation

The phrase "power generation", when used to modify such words as design basis, evaluation, and objective, indicates that the design basis, evaluation, or objective is related to the mission of the plant, which is to generate electrical power, as opposed to concerns considered to be of primary safety importance. Thus, the phrase "power generation" is used to identify aspects of the plant which are not considered to be of primary importance with respect to safety.

D. Power Generation Design Basis

The power generation design basis for a system states in functional terms the unique design requirements which establish the limits within which the power generation objective shall be met.

E. Power Generation Evaluation

A power generation evaluation shows how the system satisfies some or all of the power generation design bases. Because power generation evaluations are not directly pertinent to public safety, they are generally not included. However, where a system or component has both safety and power generation objectives, a power generation evaluation can be used to clarify the safety versus power generation capabilities.

F. Power Generation Objective

A power generation objective describes in functional terms the purpose of a system or component as it relates to the mission of the plant. This includes objectives which are specifically established so the plant can fulfill the following purposes:

1. The generation of electrical power through planned operation.

2. The avoidance of conditions which would limit the ability of the plant to generate electrical power.

3. The avoidance of conditions which would prevent or hinder the return to conditions permitting the use of the plant in order to generate electrical power following an anticipated operational occurrence, accident, or special event.

G. Safety

The word safety, when used to modify such words as design basis, evaluation, and objective, indicates that the design basis, evaluation or objective is related to concerns considered to be of safety significance, as opposed to the plant mission which is to generate electrical power. Thus, the word safety is used to identify aspects of the plant which are considered to be of primary importance with respect to safety.

H. Safety Design Basis

The safety design basis for a system states in functional terms the unique design requirements that establish the limits within which the safety objective shall be met.

I. Safety Evaluation

A safety evaluation shows how the system satisfies the safety design basis. A safety evaluation is performed only for those systems having a safety design basis.

J. Safety Objective

A safety objective describes in functional terms the purpose of a system or component as it relates to conditions considered to be of primary significance to the protection of the public. This relationship is stated in terms of radioactive material barriers or radioactive material release.

1.3 METHODS OF TECHNICAL PRESENTATION

1.3.1 PURPOSE

The purpose of this Final Safety Analysis Report (FSAR) is to provide the technical information required by section 50.34 of 10 CFR 50 to establish a basis for evaluation of the plant with respect to the issuance of a facility operating license.

1.3.2 RADIOACTIVE MATERIAL BARRIER CONCEPT

The relationship between plant behavior and offsite radiological effects is reflected in the design of this plant; therefore, information presented in this report about a system or component is the relationship of the system or component to the radioactive material barrier. Systems that must operate to preserve or limit the damage to the radioactive material barriers are described in detail. Systems that have little relationship to the radioactive material barriers are described in only as much detail as is necessary to establish their functional role in the plant.

1.3.3 ORGANIZATION OF CONTENTS

1.3.3.1 Subdivisions

The FSAR is organized into 14 chapters, each of which consists of a number of sections that are numerically identified by two numerals separated by a decimal; e.g., 3.4 is the fourth section of chapter 3. Further subdivisions are referred to as subsections and then as paragraphs.

Section 1.6 presents a brief description of the plant. Chapter 2 contains a description and evaluation of the site and environs, and supports the suitability of the site for reactors of the size and type described. Chapters 3 through 13 present detailed information about the design and operation of the plant. The nuclear safety systems and engineered safeguards are integrated into these chapters according to system function (e.g., emergency core cooling, control), system type (e.g., electrical, mechanical), or their relationship to a particular radioactive material barrier. Chapter 3, Reactor, is cross-referenced to HNP-2-FSAR chapter 4, which describes plant components and presents design details that are most pertinent to the fuel barrier. Chapter 4, Reactor Coolant System, describes plant components and systems that are most pertinent to the nuclear system process barrier. Chapter 5 describes the primary and secondary containments. Thus, chapters 3, 4, and 5 are arranged according to the four radioactive material barriers.

Chapters 6 through 13 group system information according to plant function (e.g., radioactive waste control, emergency core cooling, power conversion control), or system type, (e.g., electrical, structures). HNP-2-FSAR chapter 15, Safety Analysis, provides an overall safety evaluation of the plant which demonstrates both the adequacy of equipment designed to protect the radioactive material barriers and the ability of the safeguard features to mitigate the consequences of situations in which one or more radioactive material barriers are assumed damaged.

The general organization of a section that describes a system or component is as follows:

- Objective.
- Design basis.
- Description.
- Evaluation.
- Inspection and testing.

To clearly distinguish the safety aspects versus the power generation aspects of the system, the objective, the design basis, and the evaluation titles are modified by the word "safety" or the words "power generation" according to the definitions given in section 1.2. A safety evaluation describes how the system satisfies the safety design basis. A power generation evaluation is included when clarification of the safety and the power generation functions is needed. Applicable supporting technical material is referenced within each section of the text.

The appendices discuss, and in some cases provide a reference for the nuclear safety operational analysis, the Technical Specifications, the quality assurance program, the inservice inspection program, the off-gas release rate limit calculations, and the various criteria used in the design of the plant.

1.3.3.2 References

Refer to HNP-2-FSAR paragraph 1.1.8.3.

1.3.3.3 Tables, Figures, and Drawings

Refer to HNP-2-FSAR paragraph 1.1.8.4.

1.3.3.4 Numbering of Pages

Refer to HNP-2-FSAR paragraph 1.1.8.5.

1.3.3.5 Amending the FSAR

Refer to HNP-2-FSAR paragraph 1.1.8.6.

1.3.3.6 Historical Information

Refer to HNP-2-FSAR paragraph 1.1.8.7.

1.4 (Deleted)

1.5 (Deleted)

1.6 PLANT DESCRIPTION

1.6.1 GENERAL

1.6.1.1 Site and Environs

See subsection 1.2.1 of the HNP-2-FSAR.

1.6.1.2 Facility Arrangement

See subsection 1.2.2 of the HNP-2-FSAR.

1.6.1.3 Nuclear System

See subsection 1.2.3 of the HNP-2-FSAR.

1.6.1.4 Power Conversion Systems

See subsection 1.2.4 of the HNP-2-FSAR.

1.6.1.5 Electrical Power System

See subsection 1.2.5 of the HNP-2-FSAR.

1.6.1.6 Radioactive Waste Systems

See subsection 1.2.6 of the HNP-2-FSAR.

1.6.2 NUCLEAR SAFETY SYSTEMS AND ENGINEERED SAFEGUARDS

See subsection 1.2.7 of the HNP-2-FSAR.

1.6.3 SPECIAL SAFETY SYSTEMS

See subsection 1.2.8 of the HNP-2-FSAR.

1.6.4 PROCESS CONTROL AND INSTRUMENTATION

See subsection 1.2.9 of the HNP-2-FSAR.

1.6.5 AUXILIARY SYSTEMS

See subsection 1.2.10 of the HNP-2-FSAR.

1.6.6 STRUCTURES AND SHIELDING

See subsection 1.2.11 of the HNP-2-FSAR.

1.6.7 IMPLEMENTATION OF LOADING CRITERIA

See subsection 1.2.12 of the HNP-2-FSAR.

1.6.8 COMPONENTS MANUFACTURED OUTSIDE THE UNITED STATES

A. The 2-in. and smaller nuclear service gates, globe, and check valves used in HNP-1 were designed and manufactured outside of the United States of America (USA).

1. The forging material used in these valves was made in the USA.

2. The fabricator is Velan Valve Corporation-Montreal, Canada. Velan is a reputable valve manufacturing facility in Canada that has supplied valves for nuclear jobs throughout the USA. Velan was the first company to secure the N stamp from the American Society of Mechanical Engineers (ASME).

3. All valves were designed in accordance with the ASME Draft Code for Pumps and Valves for Nuclear Power in force at the time of the purchase order.

4. The quality assurance (QA) program adhered to during the fabrication was Velan's ASME approved program developed in response to Bechtel's purchase specification--Quality Control Plans--and other requirements outlined in the purchase order of these valves. Velan was assigned responsibility for ensuring the proper and complete implementation of the program. In addition, Bechtel monitored Velan's compliance with the program through all phases of the fabrication. Bechtel, along with the owner, reviewed and approved the QA program.

B. There were only three components within the General Electric (GE) scope-of-supply fabricated in part or in whole outside the USA. These components were all procured from Byron-Jackson Pump Division of Borg-Warner Corp-Los Angeles, California. All engineering and design were performed by Byron-Jackson in accordance with GE *purchase specifications. The following is a breakdown, by component, of the fabrication work accomplished outside the USA.*

1. *Reactor Recirculation Pumps*

   Because of a strike at the GE Foundry in Schenectady where the pumps were cast, the pump cases were sent to the Canadian GE Co, Ltd in Scarborough-Ontario, Canada, for weld repair and performance of the core closure welds.

   a. *All materials for this work were procured in the USA.*

   b. *Canadian GE Co's previous experience includes fabrication of various components; e.g., pressure vessels, control codes, fuel handling devices, etc., for heavy water reactors built in Canada.*

   c. *The codes and standards applied to this work were the applicable USA codes and standards in effect at the time of purchase placement with Byron-Jackson-Los Angeles.*

   d. *The QA program adhered to during this work was the Byron-Jackson Pump Division program developed in response to GE's purchase specification--Quality Control Plans--outlined in the purchase order for the pump. Byron-Jackson Pump Division--Los Angeles was assigned responsibility for ensuring the proper and complete implementation of the program. In addition, GE monitored Byron-Jackson's compliance with the QA program through all phases of fabrication.*

2. *Residual Heat Removal (RHR) & Core Spray Pumps*

   These pumps were both fabricated and tested by Byron-Jackson, Ltd., a division of Borg-Warner Corp-Toronto-Ontario, Canada.

   a. *All materials, with the exception of the minor attachment materials for the RHR pumps, were procured from Canadian firms.*

   b. *Byron-Jackson fabricated the primary coolant pumps for every nuclear power plant in Canada (CANDU, PICKERING & BRUCE), in addition to the fabrication of numerous auxiliary and secondary pumps for nuclear applications.*

   c. *Same as 1.c*

   d. *Same as 1.d*

1.6.9 THE EFFECTS OF ACCIDENTAL SPILLS IN THE RIVER

No commercial barge traffic travels on the Altamaha River, and the nearest upstream industrial plant is located near Macon. Therefore, if any appreciable amounts of corrosive liquids were released into the river at industrial installations located upstream, they would be diluted upon reaching the plant site to a point that no damage would occur.

Any oil reaching the plant intake structure would float upon the surface of the river, thereby minimizing the amount sent through the service water system. The heat transfer surfaces of the heat exchangers might be affected initially, but the heat transfer safety factor and the continual flushing of normal service water flow would negate the effect.

1.6.10 ESSENTIAL PIPING AND DUCTING OUTSIDE OF STRUCTURES

Essential piping and underground ducts that interconnect the reactor building, control building, diesel generator building and the intake structure are indicated in figure 1.6-1, and drawing nos. H-11353 through H-11355. All of the piping and ducting penetrates the reactor building either below grade or through adjacent buildings.

The functional capability for these penetrations is verified by the same method as for buried and interbuilding Seismic Class 1 piping described in paragraph 12.3.3.2.1.2. Tornado-generated missiles will not impair the functional capability of the duct runs and penetrations.

Control cables for equipment installed in the diesel generator building are installed in cable ducts to the control building. Three underground reinforced concrete ducts and pullboxes are designed for these cables. One duct contains control cables for one generator and one division of redundant engineered safety feature (ESF) cables. The second duct contains cables for the second generator and the second division of ESF cables. The third duct contains control cables for the third generator.

Cables for HNP-1 and HNP-2 of the same ESF division are installed in separate ducts connected to the same pullboxes. A concrete barrier is built into each pullbox to separate HNP-1 and HNP-2 cables. Ducts for each division are separated from each other with a minimum of 12 in. between the wall of the pullbox and the adjacent duct. Since each division duct run contains cables for both HNP-1 and HNP-2, a duct section for Unit 2 exists between two Unit 1 division ducts. This gives at least 6 ft of separation between ducts for division cables of the same unit. Due to the spacing between ducts and pullboxes, it is thought that a tornado missile, assumed to be a single timber or beam, cannot damage cables of both ESF divisions. Additionally, there is a minimum of 18-in. ground cover over the reinforced concrete duct, which provides protection against tornado missiles. This protection was confirmed by calculations using the modified Petry formula. The most severe tornado missile was postulated to be a 12-in. x 4-in. x 12-ft timber, which strikes the ground with a vertical velocity of 115 mph. An additional missile was investigated that strikes the ground with a vertical velocity of 115 mph and a horizontal velocity of 300 mph (strikes ground at an angle of 21 degrees and a velocity of 320 mph). For purposes of calculation, the ground cover was assumed to be sandy soil (a conservative assumption). Additional investigating of intermediate angles showed the 21-degree missile to be the worst case. Calculations showed that the vertical missile could only penetrate 8 1/2 in. of sandy soil, as opposed to the 18 in. it would have to penetrate to strike a duct. For the 21-degree missile to strike a duct, it would have to penetrate over 50 in. of dirt, but calculations showed that it could penetrate only 44 in. of sandy soil. In these calculations no credit was taken for deflection as the missile enters the ground. Additional protection for the cables inside the duct is provided by the reinforced concrete of the duct, which has 4 in. of reinforced concrete between the first row of cables and the top of the duct.

The pullboxes are designed to meet seismic conditions. Boxes installed in roadways have steel cover plates designed for heavy truck traffic. Boxes installed out of traffic patterns extend 6 in. above grade and have a cover of 1/2-in. aluminum tread plate with reinforced T-sections on the bottom of the cover plate. Steel angles are embedded in the tops of boxes, and cover plates are secured to the angles with bolts. Gaskets are installed between cover plates and the angle frame.

Two Class 1 ducts, one for each ESF division cables are installed between the diesel generator building and the reactor building and between the diesel building and the intake structure. Nominal grade for areas between the diesel generator building and the reactor building and between the diesel generator building and the control building is el 129.0 ft. The ducts from the diesel generator building to the intake structure start at a grade of el 129.0 ft and slope to el 110.0 ft at the intake structure.

The probable maximum flood level has been estimated at el 105.0 ft. (See HNP-2-FSAR paragraph 2.4.3.5). The maximum wave crest above maximum flood level would reach el 108.3 ft. (See HNP-2-FSAR paragraph 2.4.3.6.) Since all pullboxes have a gasket under the cover, the pullboxes cannot flood from surface water. All pullboxes are installed above maximum flood level, with the exception of two.

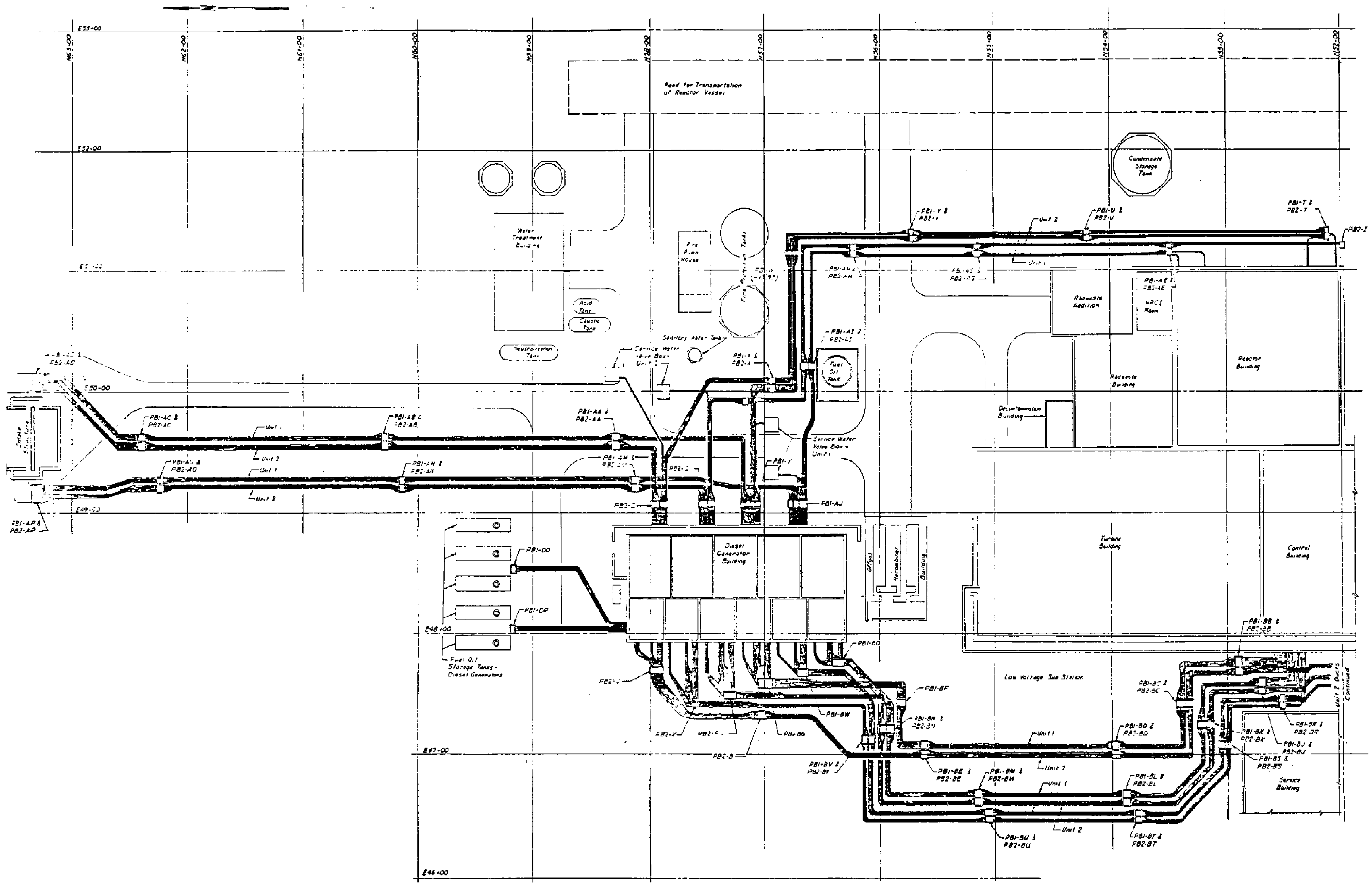
One pullbox is installed on each side of the intake structure with the top at el 110.0 ft and the floor of the box at el 103.75 ft. The centerline of the bottom row of conduits is located at el 104.83 ft and the second row at el 105.38 ft. Since the pullbox cover has a gasket, spray from water striking the structure during wave action above maximum flood level would not enter and cause flooding of the pullbox.

At the maximum flood level, water could back up through the drain and flood cables in the bottom row of conduits. Since the maximum flooding is highly intermittent and of relatively short duration, the problem of flooding should cause no problem for the cables.

Even if water can enter the pullbox through the drain, all conduits leaving the pullbox continue upward. One set of conduit continues to the diesel generator building at el 130.0 ft, and the other set continues to a pullbox above el 111.0 ft in the intake structure.

Water in the pullbox cannot follow the conduits causing damage to electrical equipment.

Some ductbank pullboxes have submersible sump pumps installed to manage the ground/rainwater seepage that enters them in an effort to prevent submerged/wetted cables from occurring. All other pullboxes are manually pumped on a PM schedule.



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

ESSENTIAL CONDUIT AND GROUNDING UNDERGROUND DUCTS

FIGURE 1.6-1

1.7 COMPARISON OF PRINCIPAL DESIGN CHARACTERISTICS

See subsection 1.3.1 of the HNP-2-FSAR.

1.8 (Deleted)

1.9 PLANT MANAGEMENT

1.9.1 ORGANIZATIONAL STRUCTURE

The Edwin I. Hatch Nuclear Plant (HNP) is operated by Southern Nuclear Operating Company (SNC). The operating, technical, and maintenance staffs are employees of SNC.

The plant is under the direction of the vice president-Hatch, who has the authority and responsibility for the safe operation of the plant. The vice president-Hatch reports to the SNC chief nuclear officer.

1.9.2 TRAINING

The operating, maintenance, and technical staffs receive extensive training and instruction in academic subjects and practical operations. These instructions are given both within and outside the plant to qualify the staff for their responsibilities and enable them to obtain United States Nuclear Regulatory Commission operator and senior operator licenses, where required. Detailed training plans are described in section 13.2 of the HNP-2-FSAR.

1.9.3 SAFETY RESPONSIBILITIES

SNC is responsible for the selection and training of personnel, all plant operations, and the execution of written normal and emergency procedures. The General Electric Company was responsible to the Applicant for the design of the nuclear steam supply system and provision of technical guidance during startup.

1.9.4 EMERGENCY PLANS

All anticipated emergencies are covered by detailed written procedures. The appropriate personnel are trained in these procedures; periodic tests and reviews are conducted. An outline of the emergency procedures is presented in section 13.5 of the HNP-2-FSAR.

1.10 QUALITY ASSURANCE PROGRAM

The Quality Assurance Program for Design and Construction is no longer in effect. The Operational Quality Assurance Program is described in chapter 17 of the HNP-2-FSAR.

1.11 RESEARCH, DEVELOPMENT, AND FURTHER INFORMATION REQUIREMENTS AND RESOLUTIONS SUMMARY

The design of the General Electric boiling water reactor (GE-BWR) for HNP-1 is based upon proven technological concepts developed during the development, design, and operation of numerous similar reactors. The Atomic Energy Commission (AEC), in reviewing HNP-1 docket and other dockets at the construction permit stage, identified several areas where further research and development efforts were required.

Several topical reports have been filed in support of the initial license application. These topical reports are listed in table 1.11-1.

Table 1.11-2 is a topic-by-topic listing of concerns applicable to large BWRs which were expressed in Advisory Committee on Reactor Safety (ACRS) letters applicable to HNP-1. In most cases, studies or design changes have been completed for resolution of these concerns. In such cases, a reference to this resolution is provided in table 1.11-2.

Appendix J gives a complete listing and detailed discussion of all significant AEC-ACRS and staff concerns.

1.11.1 INSTRUMENTATION FOR PROMPT DETECTION OF GROSS FUEL FAILURES

The principal means of detecting prompt gross fuel failures is provided by the main steam line radiation monitors. The design of this system is described in section 7.12 of the HNP-1-FSAR. Additional means of failed fuel detection are provided by the air ejector off-gas radiation monitors and the main stack radiation monitors.

A. *The assumed fission product inventories and release rates from failed fuel rods are discussed in paragraph 14.4.2.4. The basis for the chosen values is given in APED-5756, "Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor," March 1969. The correlation of fission product release with the size and type of cladding defect is very complex. Based upon empirical results for a total release from an observed number of defects, an average defect is used for calculational purposes. Refer to the response to comment 9.4.2 of the Third Supplement to the Brunswick 1 and 2 PSAR. The response to comment 7.5 of the Fourth Supplement to the Brunswick 1 and 2 PSAR discusses the activity reaching the monitors.*

B. *NEDO-10174, May 1970, discusses the question of flow blockage and its effects.*

C. *This is indicated in the response to comment 7.5 mentioned in A. above.*

D. *The background activity at the detectors is very much a function of the previous core operation in terms of the accumulated cladding defects and activity in the coolant from other sources. Discussion of the ability of the detectors to indicate a further precipitate fuel failure relative to background is given in the responses to comments 3.1 and 7.5 of the Fourth Supplement to the Brunswick 1 and 2 PSAR. Further discussion of the estimated time from failure to attainment of the setpoint signal for the various systems is given in* *subsection 7.12.6 of the HNP-1-FSAR; the relation of the setpoint signal to the number of failed fuel rods is also included.*

E. Section 7.12 of the HNP-1-FSAR provides the description and discussion of the main steam line radiation monitors that promptly detect gross fuel failure.

The setpoints for this instrumentation are given in the HNP-1 Technical Specifications.

TABLE 1.11-1 (SHEET 1 OF 3)

**TOPICAL REPORTS
SUBMITTED TO THE NRC IN
SUPPORT OF HNP-1 INITIAL LICENSE APPLICATION**

	GE Report Number	Title
1.	APED-5286	Design Basis for Critical Heat Flux in Boiling Water Reactors (September 1966)
2.	APED-5446	Control Rod Velocity Limiter (March 1967)
3.	APED-5449	Control Rod Worth Minimizer (March 1967)
4.	Deleted	
5.	APED-5453	Vibration Analysis and Testing of Reactor Internals (April 1967)
6.	APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)
7.	TR67SL211	An Analysis of Turbine Missiles Resulting from Last Stage Wheel Failure (October 1967)
8.	APED-5608	General Electric Company Analytical and Experimental Program Resolution of ACRS Safety Concern (April 1968) Not Class I
9.	APED-5455	The Mechanical Effects of Reactivity Transients (January 1968)
10.	APED-5528	Nuclear Excursion Technology (August 1967)
11.	APED-5448	Analysis Methods of Hypothetical Super-Prompt Critical Reactivity Transients in Large Power Reactors (April 1968)
12.	APED-5640	Xenon Consideration in Design of Large Boiling Water Reactors (June 1968)
13.	APED-5454	Metal Water Reactions-Effects on Core Cooling and Containment (March 1968)
14.	APED-5460	Design and Performance of General Electric Boiling Water Reactor Jet Pumps (September 1968)
15.	APED-5654	Considerations Pertaining to Containment Inerting (August 1968)

TABLE 1.11-1 (SHEET 2 OF 3)

	GE Report Number	*Title*
16.	*APED-5696*	*Tornado Protection for the Spent Fuel Storage Pool (November 1968)*
17.	*APED-5706*	*In-Core Neutron Monitoring System for General Electric Boiling Water Reactors, Rev 1 (April 1969)*
18.	*APED-5703*	*Design and Analysis of Control Rod Drive Reactor Vessel Penetrations (November 1968)*
19.	*APED-5698*	*Summary of Results Obtained From a Typical Startup and Power Test Program for a General Electric Boiling Water Reactor (February 1969)*
20.	*APED-5750*	*Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)*
21.	*APED-5756*	*Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor (March 1969)*
22.	*APED-5652*	*Stability and Dynamic Performance of the General Electric Boiling Water Reactor (April 1969)*
23.	*APED-5736*	*Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards (April 1969)*
24.	*APED-5447*	*Depressurization Performance of the General Electric Boiling Water Reactor High Pressure Coolant Injection System (June 1969)*
25.	*NEDO-10017*	*Field Testing Requirements for Fuel, Curtains, and Control Rods (June 1969)*
26.	*NEDO-10029*	*An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident (July 1969)*
27.	*NEDO-10045*	*Consequences of a Steam Line Break for a General Electric Boiling Water Reactor (July 1969)*
28.	*NEDO-10173*	*Current State of Knowledge, High Performance BWR Zircaloy Clad UO_2 Fuel (May 1970)*
29.	*NEDO-10139*	*Compliance of Protection Systems to Industry Criteria; General Electric BWR Nuclear Steam Supply System (June 1970)*

TABLE 1.11-1 (SHEET 3 OF 3)

	GE Report Number	*Title*
30.	*NEDO-10179*	*Effects of Cladding Temperature and Material on ECCS Performance (June 1970)*
31.	*NEDO-10208*	*Effects of Fuel Rod Failure on ECCS Performance (August 1970)*
32.	*NEDO-10174*	*Consequences of a Postulated Flow Blockage Incident in a Boiling Water Reactor (May 1970)*
33.	*NEDO-10189*	*An Analysis of Functional Common-Mode Failures in GE-BWR Protection and Control Instrumentation (July 1970)*

TABLE 1.11-2 (SHEET 1 OF 2)

ACRS CONCERNS - RESOLUTIONS

	ACRS Concern	Resolutions
1.	Effects of Fuel Failure on CSCS Performance	Topical Report (GE-NEDO-10208)
2.	Effects of Fuel Bundle Flow Blockage	Topical Report (GE-NEDO-10174)
3.	Verification of Fuel Damage Limit	Adequate Testing Complete; Refer to Dresden 2/3-- (GE-APED-5458, NEDO-10179)
4.	Effects of Cladding Temperature and Materials on CSCS Performance	Adequate Testing Complete; Refer to Topical Reports (GE-APED-5458, NEDO-10179)
5.	Design of Piping Systems to Withstand Earthquake Forces	Incorporated in Design
6.	Reevaluation of Main Steam Line Break Accident	Incorporated in Design Topical Report (NEDO-10045)
7.	Control Rod Block Monitor Design[a]	Incorporated in Design[a]
8.	Main Steam Line Isolation Valve Testing Under Simulated Accident Conditions	Incorporated in Design Topical Reports (GE-APED-5750) (GE-NEDO-10045)
9.	Depressurization Performance of HPCI	Incorporated in Design Topical Report (GE-APED-5447)
10.	CSCS Thermal Effects on the Reactor Vessel and Internals	Incorporated in Design Topical Report (GE-NEDO-10029)
11.	Effects of Blowdown Forces on Reactor Primary System Components	Incorporated in Design

a. Modifications implemented in 1984 (NEDC-30474-P).

TABLE 1.11-2 (SHEET 2 OF 2)

	ACRS Concern	*Resolutions*
12.	*Instrumentation for Prompt Detection of Gross Fuel Failures*[a]	*Incorporated in Design Brunswick 1/2--Supplements 3 and 4*
13.	*Diversification of CSCS Initiation Signals*	*Incorporated in Design Topical Report (GE-NEDO-10139)*
14.	*Control Systems for Emergency Power*	*Incorporated in Design*
15.	*Misorientation of Fuel Assemblies*	*Incorporated in Design*
16.	*AEC General Design Criteria No. 35 Design Intent and Conformance*	*Incorporated in Design*
17.	*Fuel Clad Disintegration Limitations*	*Incorporated in Design*
18.	*Automatic Depressurization System-Initiation Interlock*	*Incorporated in Design*
19.	*Applicant's Role--Quality Assurance Program*	*Incorporated in Design*
20.	*Offsite Emergency Plans*	*Incorporated in Design*
21.	*Flow Reference Scram Design*	*Incorporated in Design*
22.	*Radiolysis of Water*	*Testing and Analysis Complete; Refer to Dresden 3-- Amendment 23*
23.	*Scram Reliability*	*Studies Complete, Report Filed in 1970*

a. See subsection 1.11.1 for discussion.

1.12 INTERACTION OF HNP-1 AND HNP-2

The criterion followed in the design of HNP-1 and HNP-2 is that each unit shall operate independently of the other.

1.12.1 OPERATION OF HNP-1 WHILE HNP-2 IS UNDER CONSTRUCTION

Since both units are in operation, this section is not applicable.

1.12.2 SHARED STRUCTURES AND FACILITIES

1.12.2.1 Plant Stack

A 120-m stack is used to discharge the off-gas of HNP-1 and HNP-2.

1.12.2.2 Intake Structure

The river intake structure is shared by both HNP-1 and HNP-2. The structure houses plant service water and residual heat removal service water pumps.

1.12.2.3 Diesel Generator Building

The diesel generator building is designed to house the diesel generators, local control panels, and emergency switchgear for both HNP-1 and HNP-2. Each diesel generator and its control panel are physically separated from the other diesel generator units.

1.12.2.4 Control Building

HNP-1 and HNP-2 are operated from a common control room. The control panels are separated and the units controlled separately.

1.12.2.5 Refueling Floor

The reactor buildings for HNP-1 and HNP-2 are separated except above the refueling floor, which is common to both units.

1.12.2.6 Service Building

The service buildings that house office facilities for plant management personnel and related functions are shared by both HNP-1 and HNP-2.

1.12.2.7 Water Treatment Building

The water treatment building contains the well water filter and makeup dimeneralizer shared by both HNP-1 and HNP-2.

1.12.2.8 Fire Protection Pump House

The fire protection pump house contains fire protection equipment that is shared by both HNP-1 and HNP-2.

1.12.2.9 Independent Spent Fuel Storage Installation (ISFSI)

The ISFSI provides additional storage of spent fuel from both HNP-1 and HNP-2 under the general license provisions of 10 CFR 72, subpart K.

1.12.2.10 Low-Level Radwaste Pad

The low-level radwaste (LLRW) pad provides additional storage of low-level radwaste from both HNP-1 and HNP-2.

1.12.3 SHARED SYSTEMS AND EQUIPMENT

1.12.3.1 Auxiliary Electrical Power System

During normal operation, electrical power to the auxiliary loads are supplied through the unit auxiliary transformers. Each unit has one startup auxiliary transformer plus one shared startup auxiliary transformer to provide startup and shutdown power and supply the emergency busses during normal operation.

1.12.3.2 Standby AC Power Supply System

The standby ac power supply consists of two diesel generators for each unit plus one shared diesel generator.

1.12.3.3 Fuel Pool Cooling And Cleanup System

The HNP-1 fuel pool cooling and cleanup system consists of two 50% trains. One 50% train is provided on HNP-2. Since both units are not refueled simultaneously, one of the HNP-1 trains can be shared during refueling of HNP-2.

1.12.3.4 Fire Protection System

The fire protection water supply system is shared by both HNP-1 and HNP-2, as shown in the ***Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR)***.

1.12.3.5 Makeup Water Treatment System

The makeup water treatment system is designed to meet the treated water requirements for both HNP-1 and HNP-2.

1.12.3.6 Potable and Sanitary Water System

The potable and sanitary water system is designed to meet the requirements for both HNP-1 and HNP-2.

1.12.3.7 Plant Communication System

Internal and external systems are designed to provide convenient and effective communications among various plant buildings and locations.

1.12.3.8 Control Room Environmental Control System

The control room environmental control system supplies heating, ventilation, and air conditioning for the control room shared by both HNP-1 and HNP-2.

1.12.3.9 Main Stack Radiation Monitoring System

The main stack radiation monitoring system is shared by both HNP-1 and HNP-2.

1.12.3.10 Turbine Building Crane

The turbine building crane is shared by both HNP-1 and HNP-2.

1.12.3.11 Reactor Building Crane

The reactor building crane is shared by both HNP-1 and HNP-2.

1.12.3.12 Control Building Chilled Water System

The control building chilled water system is designed to provide chilled water to various coolers located in the control building shared by both HNP-1 and HNP-2.

1.12.3.13 Diesel Generator Fuel Storage and Transfer System

The diesel generator fuel storage and transfer system is designed to provide diesel fuel oil to all the emergency diesel generators located in the diesel generator building shared by both HNP-1 and HNP-2.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

Edwin I. Hatch Nuclear Plant Unit 1 and 2 Fire Hazards Analysis and Fire Protection Program.

2.0 SITE AND ENVIRONMENT

2.1 INTRODUCTION

Chapter 2 provides information regarding the site and environs of the Edwin I. Hatch Nuclear Plant-Unit 1 (Atomic Energy Commission Construction permit issued September 1969), summarizes the studies and analyses that are pertinent to the site, and sets forth the conclusions confirming site suitability.

For site studies and evaluation the following consultants were employed in the capacities listed:

- *Bechtel Corporation* — *Geology, groundwater, and seismology*
- *Pickard, Lowe, & Assoc.* — *General site consultants*
- *Dr. G. Hoyt Whipple* — *Environmental radiation and monitoring program*
- *Dr. James Halitsky* — *Meteorology*
- *Law Engineering Testing Co.* — *Foundations and groundwater*
- *Southern Company Services, Inc.* — *Hydrology*

2.2 SITE DESCRIPTION

2.2.1 LOCATION AND AREA

See subsection 2.1.1 and paragraph 2.1.2.1 of the HNP-2-FSAR.

2.2.2 TOPOGRAPHY

See subsection 2.4.1 of the HNP-2-FSAR.

2.2.3 POPULATION

At the time of submittal of the FSAR to support the license application, the information on population within a 5-mile radius was current.

For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report. For the most current information regarding operational dose estimates, consult the Annual Radiological Environmental Operating Report and the Annual Effluent Release Report.

The plant is located in Appling County, a sparsely populated region having ~ 840 permanent residents within a 5-mile radius. According to the 1970 Census, Appling County had a population of 12,726.[1] There are no population centers of 2000 or more within 10 miles of the plant, and the only population center of 10,000 or greater within 50 miles is Waycross (population 19,000) located ~ 48 miles to the south. The nearest town or location having an industry is Baxley, Georgia, located approximately 11 miles to the south, which in 1970 had a population of 3500.[1] The Georgia population centers are shown in figure 2.4-5 of the HNP-2-FSAR. The shaded areas indicate the locations of the major cities and the more heavily populated counties within the state. The estimated population for 1965 is shown within each area.

No people live onsite.

In figures 2.2-1 and 2.2-2, estimates of the projected population distribution within the site region are shown in 16 direction sectors and in 1-mile increments up to 5 miles for the years 1972, 1982, 1992, and 2012. In figures 2.2-3 and 2.2-4, estimates are shown in 10-mile increments up to 50 miles. Table 2.2-1 lists the counties falling totally or partially within a 50-mile radius of the site. The 1970 population and projected populations for the years 2012 and 2015 are presented. The last column in table 2.2-1 shows the projected population change between 2012 and 2015. An examination of this column indicates that, when the net projected population change is broken down into 16 direction sectors and mileage increments, only fractional changes could be shown in figures 2.2-3 and 2.2-4.

Refer to subsection 2.1.3 of the HNP-2-FSAR for a discussion of the origins of the above population estimates.

Public access to nearby recreational facilities is controlled as discussed in subsection 2.1.2 of the HNP-2-FSAR. Also, transient population nearby the plant (e.g., Altamaha School, etc.) is discussed in paragraph 2.1.3.3 of the HNP-2-FSAR.

Table 2.2-3 contains a listing of calculated doses for normal operation for the ecology sanctuary, visitor center, river, and road. The whole body exposure to visitors has been estimated for the expected visitor categories based on off-gas release equivalent to 100,000 μCi/s at 30 min as shown in table 2.2-3.

A. Boy scout campers

It is estimated that a camper is at the boy scout camp once a month for 2 1/2 days or a total of 30 days/year. The whole body exposure for this period is calculated to be 0.2 mrem/year. This calculation was made at a point on U.S. Hwy No. 1, 4150 ft west of the plant stack.

B. Fishermen

It is estimated that a fisherman fishes on the river 850 ft north of the plant stack for 4 h once a week for a total of 208 h/year. The whole body exposure for this period is calculated to be 0.07 mrem/year.

C. Tourists

It is estimated that a tourist stays at the visitor center 8 h/year. The whole body dose for this period is calculated to be 0.002 mrem/year.

D. Ecologists

It is estimated that an ecologist visiting the wildlife refuge might spend 8 h once a month or a total of 96 h/year. The whole body dose for this period is calculated to be 0.03 mrem/year. This calculation was made at a point across the river located 1800 ft north of the plant stack.

Refer to HNP-2-FSAR subsection 2.1.2 for a discussion of plant exclusion area control.

2.2.4 LAND USE

At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report. For the most current information on sampling for radionuclides in agricultural products, in river sediment, and fish, consult the Annual Radiological Environmental Operating Report.

The land in the site region is primarily wooded, with a small percent being used for various agricultural purposes. About 70% of the land in the five surrounding counties of Appling, Jeff Davis, Montgomery, Tattnall, and Toombs is wooded. In January 1972, GPC commissioned the Georgia Institute of Technology Industrial Development Division of the Engineering Experiment Station to make a land use survey of the site area.

Within a 50-mile radius of the site, agriculture accounts for a relatively large portion of the economy. However, as in most farming areas, the actual number of farms is decreasing while the average farm size is increasing. Field crop, general, and miscellaneous types of farms dominate this area. Livestock farms are the leading type of specialty farm, although they comprise only a small portion of the total. Within a 5-mile radius of the site, agricultural activity is devoted primarily to row crops. While many farmers raise cattle and hogs to round out their farming activities, fewer than 10 farmers in the area produce either hogs or cattle in appreciable numbers. Only one major egg production activity was indicated in the area, and no dairy farms were cited. Within the site area, ~ 7000 acres of farm land are devoted to row crops and ~ 1600 acres to pasture land. These figures do not remain constant since farmers traditionally divert farm land from one use to another.

The remaining land in the 5-mile study area is essentially forest land; however, not all of it is accessible for commercial use.

Tables 2.2-4 through 2.2-7 summarize data gathered for Appling and Toombs Counties (plant site vicinity) by the U.S. Bureau of Census.

Table 2.2-8 identifies the dairying operations in the site vicinity and states each size and market. Only dairy operations no. 8, 11, and 12, identified in this table, are located within 10 miles of the plant site. They are located ~ 7, 8, and 9 air miles from the site, respectively. Figure 2.2-5 indicates the locations of the dairy operations.

Existing pasture land is abundant and a portion where beef cattle occasionally graze adjoins the southwest corner of the plant site. Therefore, it is conceivable that this grazing area could someday become the nearest dairy operation.

Concerning fishing activities in the site vicinity, the Altamaha River is used extensively for sport fishing. The north bank of the river at the U.S. Hwy No. 1 bridge is available for boat launching. Access to the south bank of the river is available at a privately-owned fishing camp located ~ 1/2 mile west of the highway.

See section 2.2 of the HNP-2-FSAR for a discussion of nearby industrial, transportation, and military facilities.

REFERENCES

1. *1970 Census of Population, Final Population Counts: Georgia, U.S. Department of Commerce, Bureau of the Census, advance report PC(VI-12), Washington, D.C., December 1970.*

TABLE 2.2-1

PROJECTED POPULATION CHANGE FROM 2012 THROUGH 2015 WITHIN 50-MILE RADIUS OF SITE[(a)(b)]

County	*1970 Population*	*Projected 2012 Pop*	*Projected 2015 Pop*	*Difference in Population 2012-2015*
Appling	*12,750*	*14,720*	*14,800*	*+ 80*
Atkinson	*5900*	*7720*	*7800*	*+ 80*
Bacon	*8250*	*14,160*	*14,500*	*+ 340*
Ben Hill	*13,150*	*14,820*	*14,900*	*+ 80*
Bryan	*6550*	*11,320*	*11,600*	*+ 280*
Bulloch	*31,600*	*26,720*	*26,800*	*+ 80*
Candler	*6400*	*5520*	*5400*	*- 120*
Coffee	*22,850*	*36,820*	*37,800*	*+ 980*
Dodge	*15,650*	*16,960*	*17,000*	*+ 40*
Emanuel	*18,200*	*19,700*	*19,800*	*+ 100*
Evans	*7300*	*8700*	*8800*	*+ 100*
Jeff Davis	*9450*	*14,200*	*14,500*	*+ 300*
Laurens	*32,750*	*49,600*	*50,000*	*+ 400*
Liberty	*17,550*	*23,580*	*24,100*	*+ 520*
Long	*3750*	*4000*	*4000*	*0*
Montgomery	*6100*	*4120*	*4100*	*- 20*
Pierce	*9300*	*7620*	*7500*	*- 120*
Tattnall	*16,550*	*15,140*	*15,100*	*- 40*
Telfair	*11,400*	*8480*	*8300*	*+ 160*
Toombs	*19,150*	*19,640*	*19,800*	*+ 160*
Ware	*33,550*	*56,520*	*57,800*	*+ 1280*
Wayne	*17,850*	*24,040*	*24,400*	*+ 360*
Wheeler	*4600*	*4080*	*3200*	*- 880*
Totals	*330,600*	*408,180*	*412,000*	*+ 3820 (net change)*

a. Data are presented according to counties.

b. At the time of submittal of the FSAR to support the license application, the information on population projections was based on the 1970 Census data. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report.

TABLE 2.2-3

NORMAL OPERATION - ECOLOGY SANCTUARY, VISITOR CENTER, RIVER, AND ROAD DOSES[d]

Location	Sector	Release Point	Noble Gas Release (μCi/s)	Whole Body Gamma Dose (mrem/year)
WHOLE BODY DOSE				
Ecology preserve	N(1800 ft)	Stack	4960[a]	2.6
Ecology preserve	N(1800 ft)	Vent	15[b]	.042
Visitor center	SW(2500 ft)	Stack	4960[a]	2.2
Visitor center	SW(2500 ft)	Vent	15[b]	.020
River and road	N(850 ft)	Stack	4960[a]	2.8
River and road	N(850 ft)	Vent	15[b]	.073
River and road	W(3650 ft)	Stack	4960[a]	2.4
River and road	W(4150 ft)	Vent	15[b]	.012
			Noble Gas Release (μCi/s)	Beta Skin Dose (mrem/year)
SKIN DOSE				
Ecology preserve	N(1800 ft)	Stack	4960[a]	.07
Ecology preserve	N(1800 ft)	Vent	15[b]	.16
Visitor center	SW(2500 ft)	Stack	4960[a]	.21
Visitor center	SW(2500 ft)	Vent	15[b]	.05
River and road	N(850 ft)	Stack	4960[a]	.001
River and road	N(850 ft)	Vent	15[b]	.54
River and road	W(3650 ft)	Stack	4960[a]	.19
River and road	W(4150 ft)	Vent	15[b]	.013
			Iodine Release (μCi/s)	Inhalation Dose (mrem/year)
Ecology preserve	N(1800 ft)	Stack	.018[c]	.002
Ecology preserve	N(1800 ft)	Vent	.005[b]	.11
Visitor center	SW(2500 ft)	Stack	.018[c]	.007
Visitor center	SW(2500 ft)	Vent	.005[b]	.042
River and road	N(850 ft)	Stack	.018[c]	$3.5x10^{-5}$
River and road	N(850 ft)	Vent	.005[b]	$3.3x10^{-1}$
River and road	W(3650 ft)	Stack	.018[c]	$6.4x10^{-3}$
River and road	W(4150 ft)	Vent	.005[b]	$2.9x10^{-2}$

a. SJAE + gland-seal effluent for 100,000 μCi/s at 30 min.
b. Hypothetical 7 gal/min leak.
c. Gland-seal effluent.
d. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report. For the most current information regarding operational dose estimates, consult the Annual Radiological Environmental Operating Report and the Annual Effluent Release Report.

TABLE 2.2-4

FARM TYPES IN APPLING AND TOOMBS COUNTIES[a][b][c]

Product	*Appling*	*Toombs*
Field Crops	*318*	*224*
Vegetables	*-*	*6*
Fruits and nuts	*1*	*-*
Poultry	*11*	*9*
Dairy	*4*	*3*
Livestock	*104*	*71*
General	*235*	*143*
Miscellaneous	*213*	*162*

a. U.S. Bureau of Census, Census of Agriculture,1964.
b. In number of farms.
c. At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.

TABLE 2.2-5

AGRICULTURAL LAND USE IN APPLING AND TOOMBS COUNTIES[a][c]

	Appling	*Toombs*
Number of farms	*871*	*588*
Acreage of farms	*157,515*	*120,484*
Cropland harvested (acres)	*42,370*	*35,816*
Cropland pastured (acres)	*8992*	*9909*
Cropland not harvested or pastured (acres)	*8890*	*14,849*
Woodland pastured (acres)	*17,230*	*14,114*
Woodland not pastured (acres)[b]	*90,921*	*45,085*
Other pasture (acres)[b]	*4869*	*7234*

a. U. S. Bureau of the Census, Census of Agriculture, 1969.
b. U. S. Bureau of the Census, Census of Agriculture, 1964.
c. At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.

TABLE 2.2-6

SELECTED AGRICULTURAL UNITS SOLD IN APPLING AND TOOMBS COUNTIES[a][c]

Product	Appling	Toombs
Whole milk (lb)[b]	7,354,000	1,422,222
Broilers and other meat-type chicken	1,385,748	-
Chicken eggs (dozen)[b]	287,750	1,201,053
Cattle and calves	7274	3351
Hogs and pigs	60,070	39,580
Sheep and lambs	-	31

a. U. S. Bureau of the Census, Census of Agriculture, 1969.
b. U. S. Bureau of the Census, Census of Agriculture, 1964.
c. At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.

TABLE 2.2-7

VALUE OF AGRICULTURAL PRODUCTS SOLD IN APPLING AND TOOMBS COUNTIES[(a)(b)]

Product	*Appling*	*Toombs*
Crops (field crops, vegetables, fruits, and nuts)	*$2,851,210*	*$3,272,398*
Poultry and poultry products	*$2,540,983*	*$ 312,050*
Dairy products	*$ 527,758*	*$ 227,668*
Livestock and livestock products	*$4,123,817*	*$2,582,079*

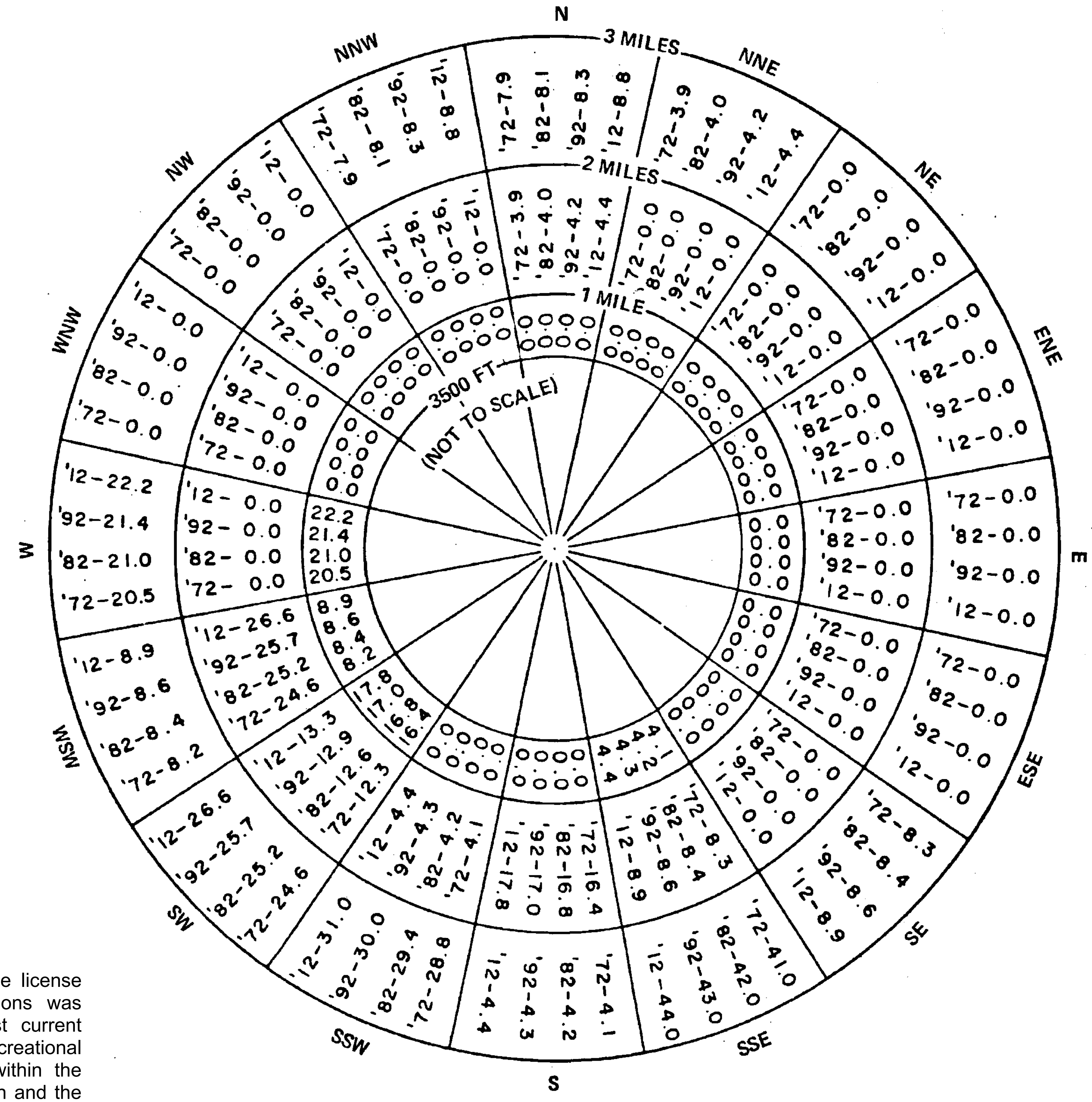
a. U. S. Bureau of the Census, Census of Agriculture, 1969.
b. At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.

TABLE 2.2-8

DAIRIES LOCATED IN THE PLANT HATCH VICINITY[a]

Dairy Number and Location (County)	Owner and/or Operator	Dairy Herd	Total Herd	Acreage	Market
1-Montgomery	Mrs. Ben Conner	190	300	280	Bordens-Macon
2-Toombs	H. L. & W. B. Thompson	160	190	600	Pet Milk-Waycross
3-Toombs	H. C. Fountain	3	4	3	Raw milk-Sold locally
4-Tattnall	Georgia Prison System	200	500	Dairy 400 Prison 8900	Process own for prison use
5-Wayne	J. W. Beck	57	129	100	Pet Milk-Waycross
6-Appling	W. V. Head	275	425	1200	Pet Milk-Waycross
7-Appling	C. S. Griffen	126	150	225	Pet Milk-Waycross
8-Appling	A. M. Stone	50	60	290	Pet Milk-Waycross
9A-Appling	C. M. Morris & Sons	400	500	1100	Pet Milk-Waycross
9B-Appling	C. M. Morris & Sons	166	230	300	Pet Milk-Waycross
10-Appling	Georgia Baptist Children's Home	126	140	2386	Pet Milk-Waycross
11-Jeff Davis	E. E. Sellers & Sons	115	200	386	Pet Milk-Waycross
12-Jeff Davis	Sellers Johnson	98	118	360	Pet Milk-Waycross

a. At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.



POPULATION DISTRIBUTION
0-3 MILES
(1972, 1982, 1992, AND 2012)

NOTE:
At the time of submittal of the FSAR to support the license application, the information on population projections was based on the 1970 Census data. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report.

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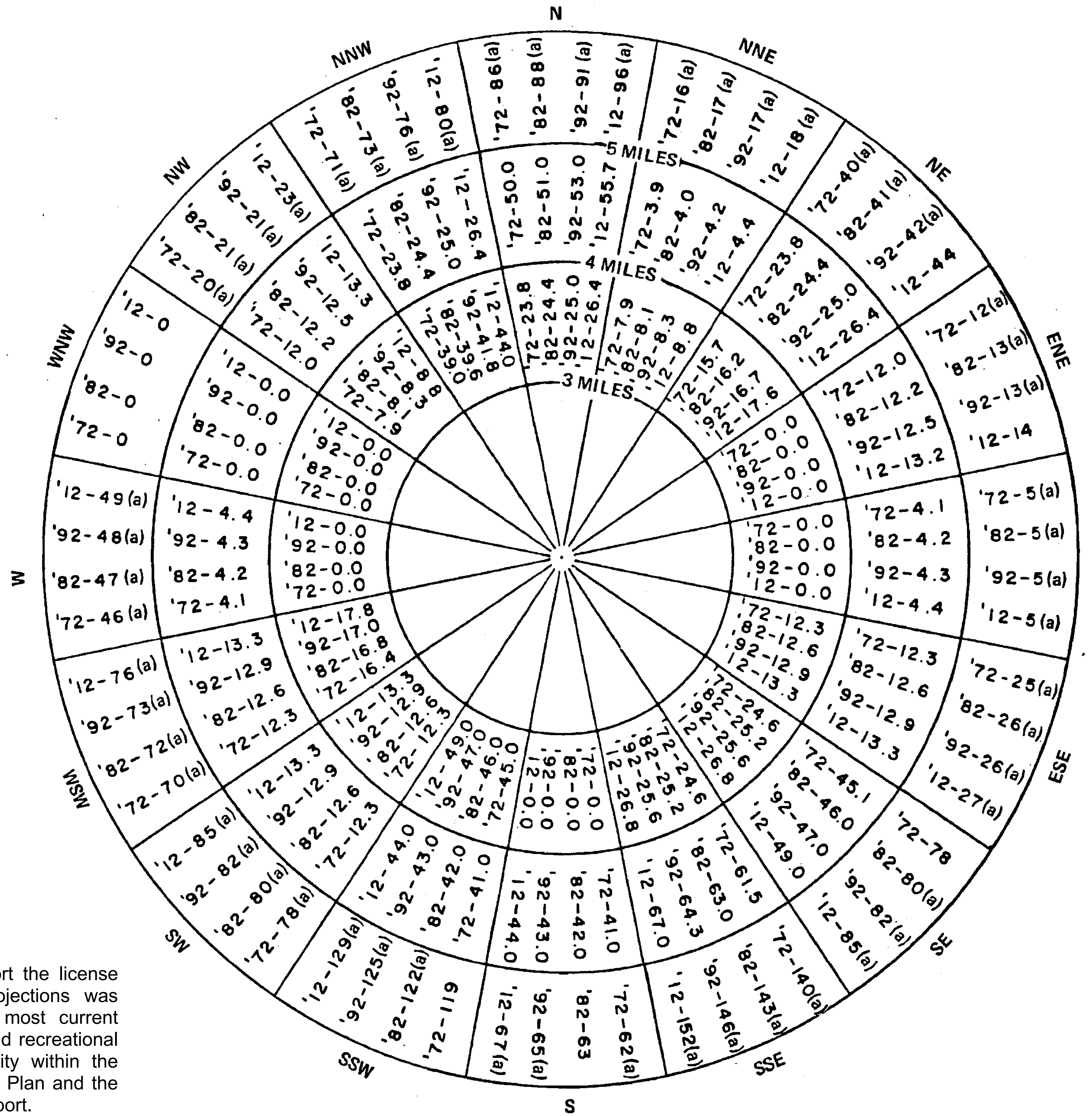
SOUTHERN COMPANY *Energy to Serve Your World®*	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	POPULATION DISTRIBUTION (0-3 MILES)
		FIGURE 2.2-1

POPULATION DISTRIBUTION
3-5 MILES
(1972, 1982, 1992, AND 2021)[(a)]



(a) Fractional totals rounded to the next highest whole number

NOTE:
At the time of submittal of the FSAR to support the license application, the information on population projections was based on the 1970 Census data. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report.

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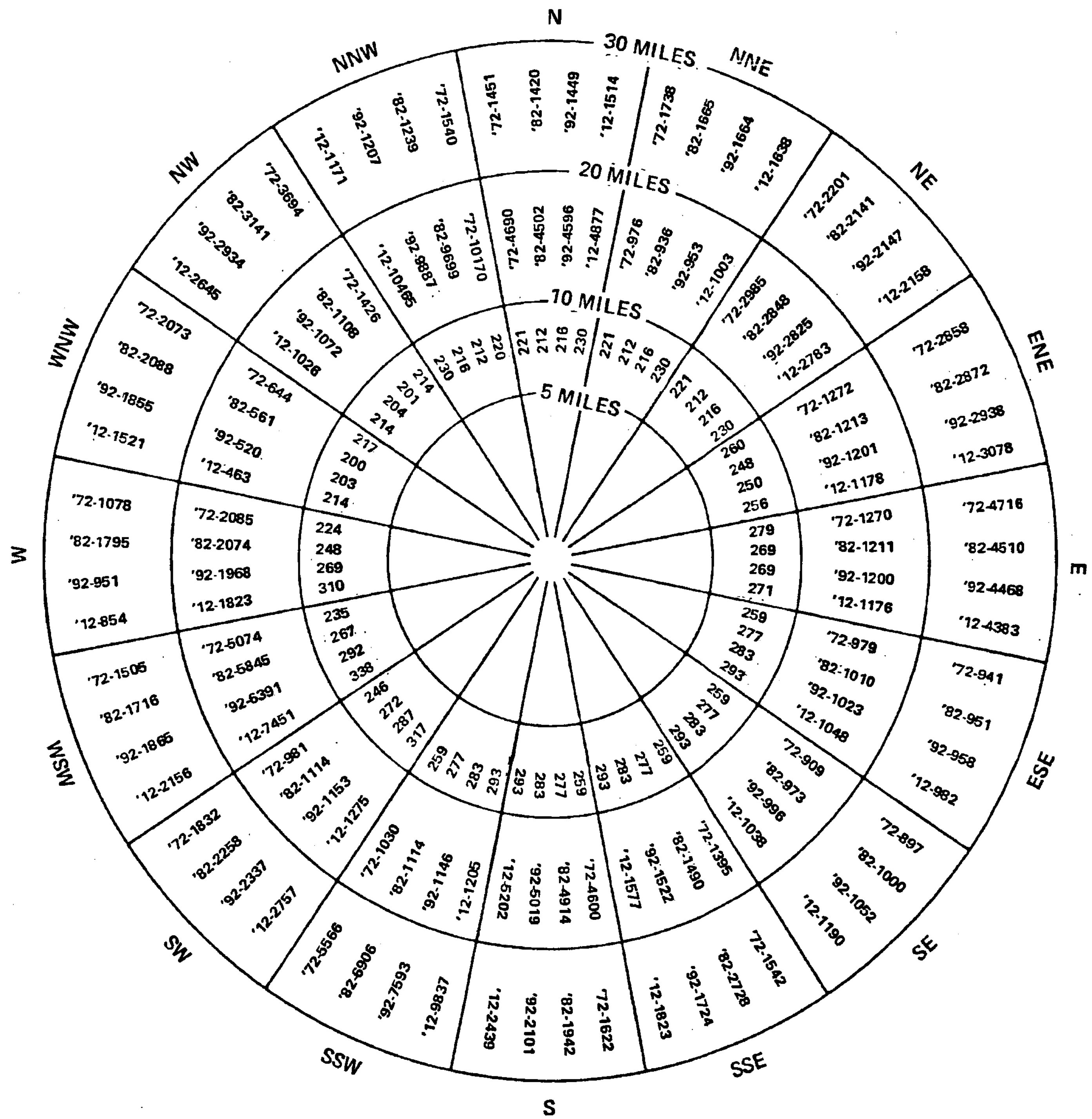
POPULATION DISTRIBUTION
(3-5 MILES)

FIGURE 2.2-2

POPULATION DISTRIBUTION
5-30 MILES
(1972, 1982, 1992, AND 2021)



NOTE:
At the time of submittal of the FSAR to support the license application, the information on population projections was based on the 1970 Census data. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report.

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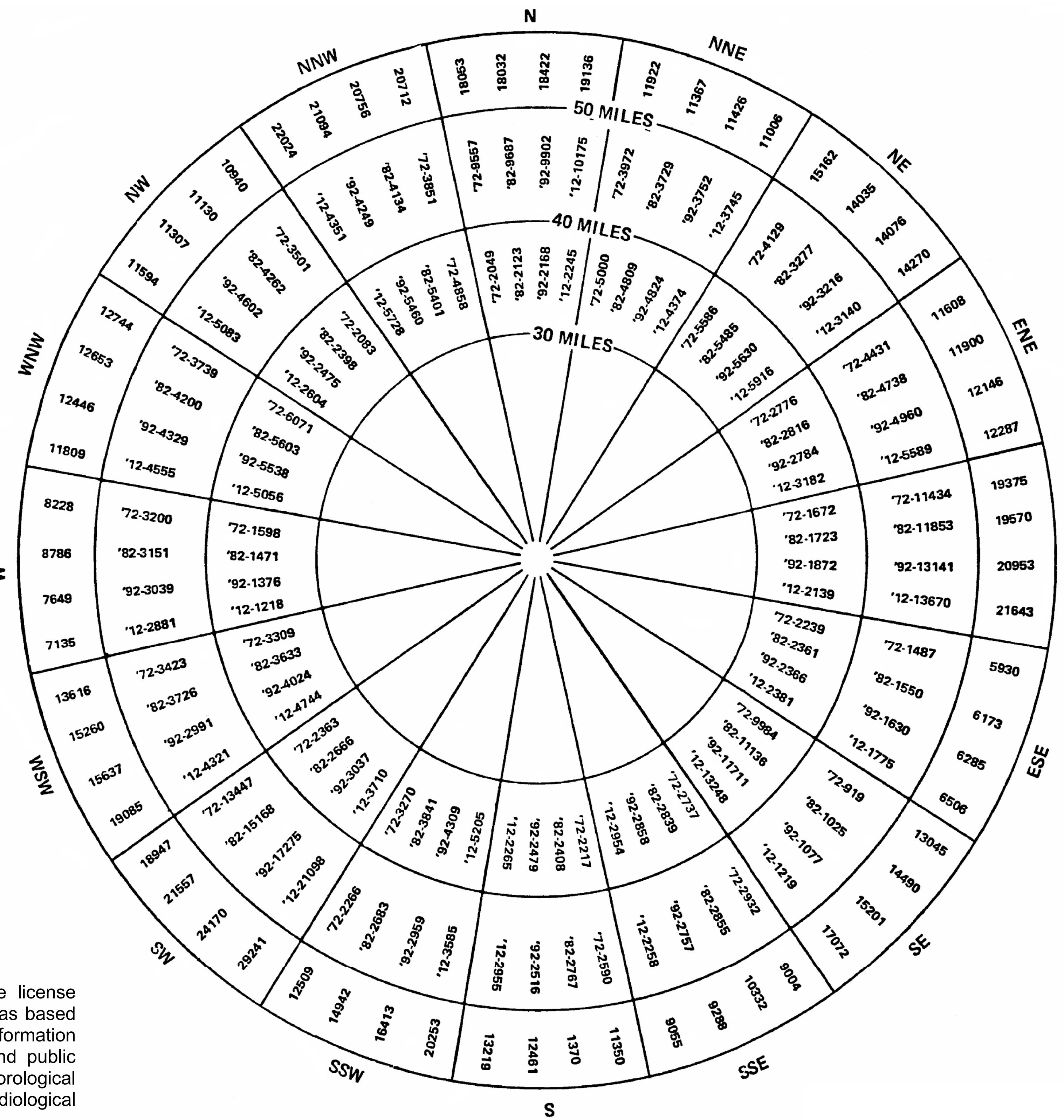
POPULATION DISTRIBUTION
(5-30 MILES)

FIGURE 2.2-3

POPULATION DISTRIBUTION
30-50 MILES
(1972, 1982, 1992, AND 2021)[a]



a. Outermost figures indicate 0-50 mile sector totals.

NOTE:
At the time of submittal of the FSAR to support the license application, the information on population projections was based on the 1970 Census data. For the most current information regarding the population, schools, and recreational and public areas, as well as population density within the 16 meteorological zones, consult the Emergency Plan and the Annual Radiological Environmental Operating Report.

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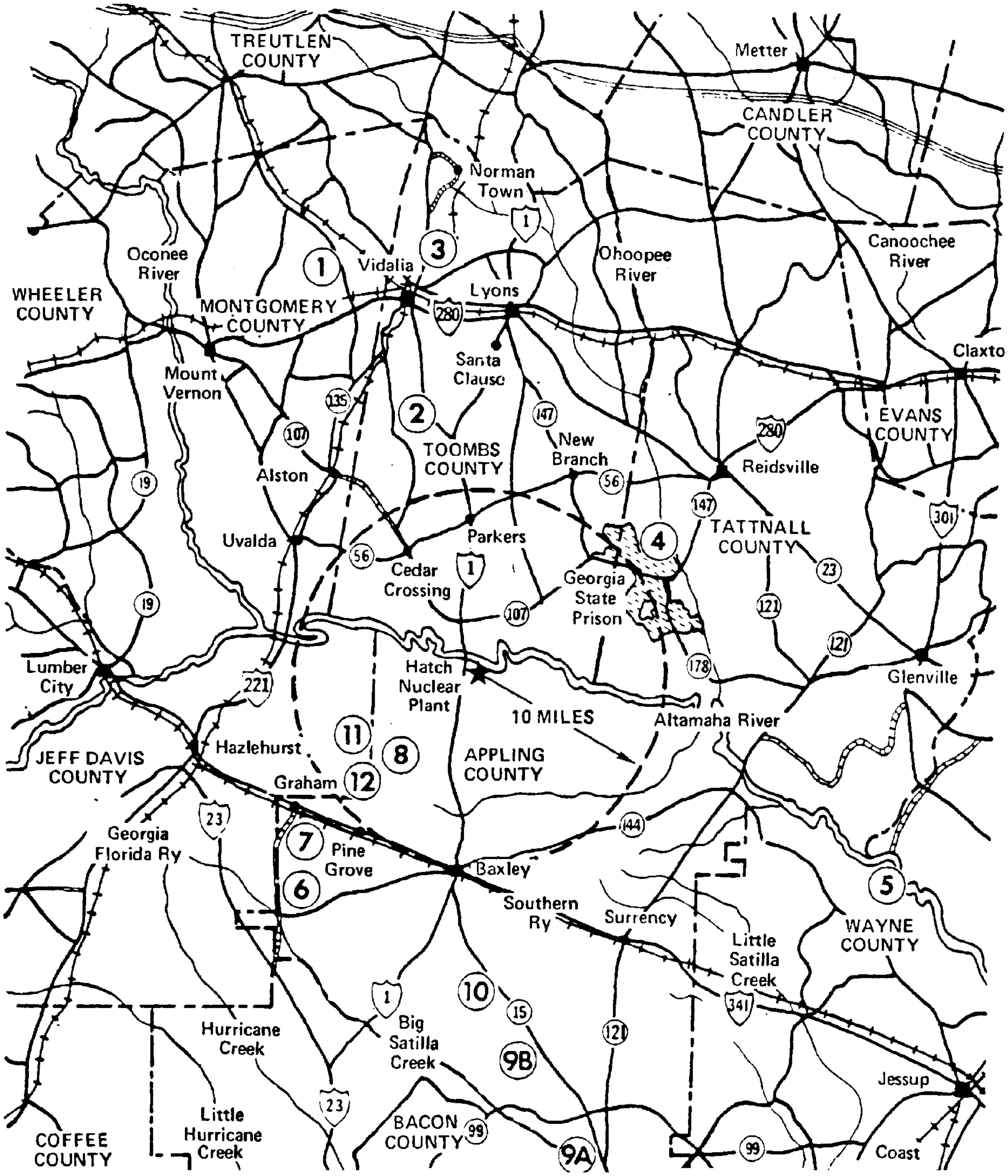
POPULATION DISTRIBUTION
(30-50 MILES)

FIGURE 2.2-4



NOTE: At the time of submittal of the FSAR to support the license application, the information on agricultural production within a 5-mile radius was current. For the most current information on agricultural production areas, consult the Annual Radiological Environmental Operating Report.

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LOCATION OF DAIRY OPERATIONS IN VICINITY OF SITE

FIGURE 2.2-5

2.3 METEOROLOGY

Meteorological information for HNP-2 applies to the plant site in general, including HNP-1. Therefore, refer to HNP-2-FSAR section 2.3 for a discussion of meteorology.

2.4 HYDROLOGY

See section 2.4 of the HNP-2-FSAR.

2.5 GEOLOGY AND SEISMOLOGY

2.5.1 INTRODUCTION - GEOLOGY

See section 2.5 of the HNP-2-FSAR.

2.5.2 REGIONAL GEOLOGY

See section 2.5 of the HNP-2-FSAR.

2.5.3 SITE GEOLOGY

See section 2.5 of the HNP-2-FSAR.

2.5.4 CONCLUSIONS

See section 2.5 of the HNP-2-FSAR.

2.5.5 INTRODUCTION - SEISMOLOGY

The engineering seismologic studies include:

- *Literature research to evaluate the seismicity of the area.*
- *An evaluation of the tectonics of the region with respect to available credible information.*
- *An analysis to evaluate the response of the foundation materials under earthquake-type loadings.*

2.5.6 SEISMIC HISTORY

See paragraphs 2.5.2.5 and 2.5.2.9 of the HNP-2-FSAR.

2.5.7 SEISMIC DESIGN

2.5.7.1 General

No active or recent faulting has been mapped in the area of the plant site. The area is not seismically active; however, the effects of earthquakes from distant sources may be experienced at the site. The Charleston, South Carolina earthquake of 1886, the epicenters of which were located ~ 150 miles northeast of the site, is the type which may be felt at the site.

The design of a nuclear power plant requires selecting an operating basis earthquake (OBE) on the basis of historical events and a design basis earthquake (DBE) on predicted events.

2.5.7.2 OBE (Maximum Expectable)

The long historic record of ~ 200 years indicates the highest ground motion experienced at the site accompanied the Charleston, South Carolina earthquake of August 31, 1886. Dutton's isoseismal map shows the maximum intensity which occurred in the vicinity of the site was a moderate VI on the Modified Mercalli Scale. However, to be conservative, a peak horizontal surface acceleration of 0.08 g was selected; this corresponds to a high intensity VI shock.

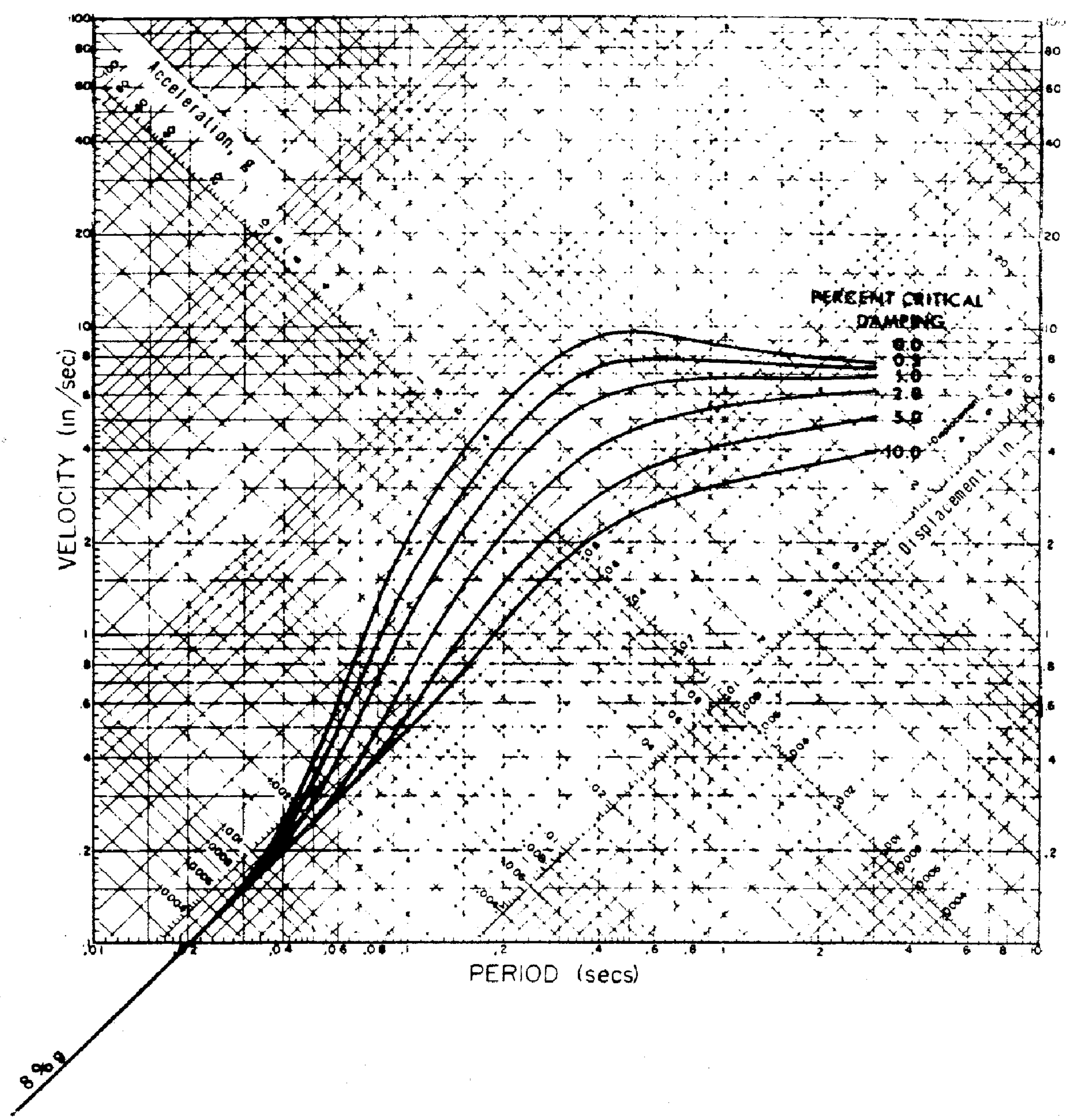
2.5.7.3 DBE (Hypothetically Expectable)

The damaging effects of the Charleston earthquake upon the Savannah, Georgia area, ~ 70 miles from the plant site and in the general direction of the epicenter, were selected as the basis for determining the DBE acceleration. An intensity VII has been assigned to the damage which occurred in Savannah. This is the greatest observed within 100 miles of the plant site and is also about twice the maximum acceleration which has occurred in 200 years at the site. An intensity VII has been determined as the maximum which could occur at the site and is the worst interpretation of the damage suffered at Savannah from the Charleston earthquake. Savannah, Georgia is 70 miles nearer to Charleston than the plant area. Intensity VII is considered exceptionally conservative and corresponds to a peak horizontal surface acceleration of 0.15 g.

2.5.8 DESIGN SPECTRA

The surficial design spectra are presented in figures 2.5-2 and 2.5-3. They are the spectra for the OBE and DBE, respectively. These spectra conform to the average spectra developed by Dr. George W. Housner for the period range from ~ 4 s and lower.

The spectra have been normalized to a peak horizontal ground surface acceleration of 0.08 g and 0.15 g for the OBE and DBE, respectively.



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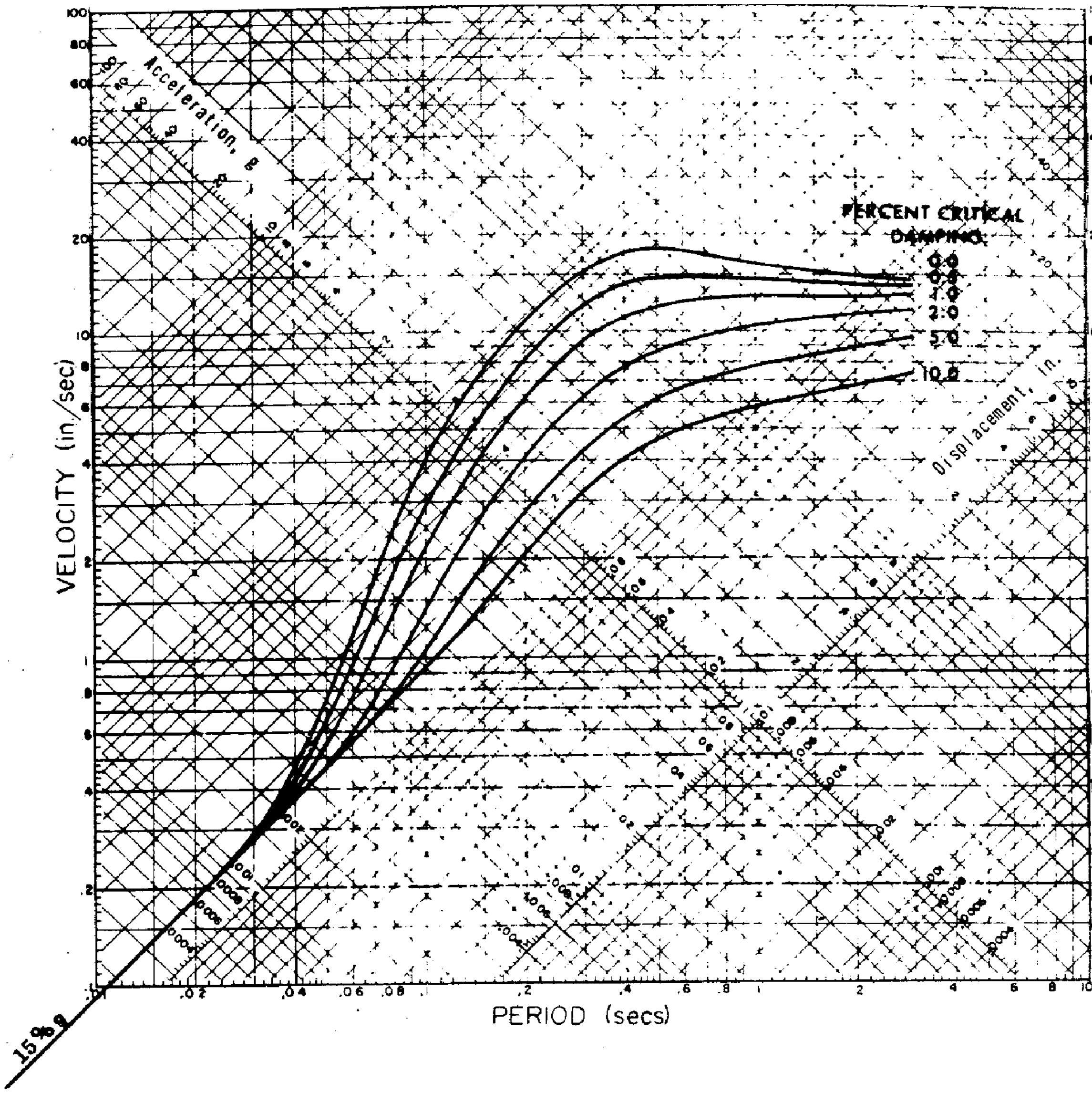
PLANT SITE SEISMIC DESIGN CRITERIA
RECOMMENDED RESPONSE SPECTRA OBE

FIGURE 2.5-2



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PLANT SITE SEISMIC DESIGN CRITERIA
RECOMMENDED RESPONSE SPECTRA DBE

FIGURE 2.5-3

2.6 RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

The current radiological environmental monitoring program is described in the Offsite Dose Calculation Manual.

2.7 FOUNDATIONS AND BORINGS

2.7.1 GENERAL

The information in this section is presented under the following six headings:

- *Investigations.*
- *Laboratory testing.*
- *Subsurface classification and description.*
- *Structural data.*
- *Foundation evaluation.*
- *Liquefaction potential.*

2.7.2 INVESTIGATIONS

Along with, and in addition to, the geologic and seismic explorations, detailed foundation investigations including borings were completed for use in the design of the foundations for the structures.

2.7.2.1 Summary of Soil Test Boring

Site investigations included soil test borings made at 125 locations. Of the total, 79 borings were completed for the principal purpose of soil classification, analysis, and testing to establish and confirm foundation design criteria for the principal structures. Forty-one soil test borings were located either within or in areas immediately adjacent to the reactor, radwaste, turbine, intake, diesel generating, and main stack structures (figures 2.7-1 through 2.7-4). Test boring records for those borings included to illustrate the subsurface profiles (figures 2.7-5 through 2.7-11) are included in Supplement 2B of the HNP-2-FSAR, and they graphically show soil descriptions and penetration resistances.

2.7.2.2 Summary of Boring and Sampling Procedures

Soil sampling and penetration testing were performed in accordance with American Society of Testing Materials (ASTM) Specification D 1586-64T. Representative portions of the soil samples thus obtained were placed in glass jars and transported to the soils laboratory. In the laboratory, the samples were examined to verify the driller's field classifications.

Split spoon samples are suitable for visual examination and classification tests but are not sufficiently intact for qualitative laboratory testing. Undisturbed samples were obtained by forcing sections of 3-in. outside diameter tubing into the soil at the desired sampling levels. This sampling procedure is described *by ASTM Specification D 1587. Each tube, together with the encased soil, was carefully removed from the ground, made airtight, and transported to the laboratory. Locations and depths of undisturbed samples are shown on the test boring records.*

2.7.2.3 Summary of Ground Water Investigations

Ground water investigations are summarized in section 2.4.

2.7.3 LABORATORY TESTING

See section 2A.3 of the HNP-2-FSAR.

2.7.4 SUBSURFACE CLASSIFICATION AND DESCRIPTION

Subsurface profiles developed to establish the soil formations are illustrated by figures 2.7-5 through 2.7-11.

The uppermost soils in the plant area represent the Altamaha Geological Formation and consist of firm to very dense purple, brown, and gray clayey fine to medium sand with some clay layers. These soils were encountered from the surface down to ~ el 120.

The Altamaha sands and clays are underlain by very dense gray clayey fine to medium sand which, in most locations, is partially cemented. Within this generally cemented sand zone are scattered layers and inclusions of very hard clay and very dense noncemented sands. These sands are a portion of the geologic formation identified as the Duplin Formation and extend from ~ el 70 to ~ el 80.

The cemented sands are underlain by firm to very dense gray-green fine sands and clayey fine sands which extend to ~ el 30. Within this zone, thin layers or lenses of gray-green plastic clay which vary in thickness between 3 to 6 ft were encountered between el 60 to 70. At some locations, the fine sands consistency, as measured by the standard penetration test, can be described as loose. Below el 30, dense to very dense gray slightly clayey fine sands with thin hard clay layers were encountered. The dense sands extend to approximate el 0 and are also a portion of the Duplin Formation.

Below approximate el 0, very hard gray-green silty clays were encountered. These greenish clays have been identified as a portion of the Hawthorne or Chipola Formations.

2.7.5 STRUCTURAL DATA

2.7.5.1 Reactor Building

Plan dimensions - 149 ft by 149 ft; static foundation pressure - 6.5 to 7.75 ksf; bottom of mat foundation - el 75.

2.7.5.2 Radwaste Building

Plan dimensions - 90 ft by 96 ft; static foundation pressure - 3.5 ksf; bottom of mat foundation - el 100.

2.7.5.3 Turbine and Control Buildings

Plan dimensions - The combined building is 355-ft long by 160-ft wide with the turbine building being 252-ft long and the control building 103-ft long. Average static foundation pressure - 6 ksf; bottom of mat foundation - el 105.

2.7.5.4 Diesel Generator Building

Plan dimensions - ~ 196 ft by 103.5 ft; static foundation pressure - < 3 ksf; bottom of mat foundation - el 125.

2.7.5.5 Main Stack

Plan dimensions - octagon with 36-ft inscribed radius; yard - el 119 ft, 6 in.; top of cap - el 108 ft, 6 in.; bottom of cap - el 97 ft, 6 in.; pile cutoff - el 98 ft, 3 in.; 164-14BP73 100-ton piles at 4- to 6-ft spacing in 5 rings with radii of 6 ft, 16 ft, 20 ft, 30 ft, and 34 ft, moment, 21,500-kips vertical load at pile cap. A shear of 800 kips is supported by the piles and pile cap.

2.7.5.6 Intake Structure

Plan dimensions - 130 ft by 53 ft; average static foundation pressure - 5.0 ksf; bottom of mat foundation - el 52.

2.7.6 FOUNDATION EVALUATION

The subsurface conditions which govern construction and foundation design at this site are:

- The cemented sand zone encountered by the borings between el 120 and 70.

- *The existence of ground water.*
- *The presence of firm clayey sands and plastic clays between el 50 and 70.*

The soils encountered by the borings at the foundation levels are commensurate with satisfactory foundation support.

2.7.6.1 Reactor Building

The reactor building, with its mat foundation at el 75, bears on firm to dense sands and clayey sands with layers of plastic clay. Using soil strength parameters based on triaxial test data, the computed safety factor against bearing capacity failure for this foundation is in excess of 3.

The sands which support the reactor building are, in general, dense (N=30+).

2.7.6.2 Radwaste Building

The radwaste building, with its base slab at el 100, bears on soils comparable to those described for the reactor building. These soils are capable of safely supporting the design loads for the radwaste building.

2.7.6.3 Turbine and Control Buildings

The turbine and control buildings, with the bottom of the mat foundation at el 105, bears on a relatively thick zone of cemented sands underlain by firm to dense clayey sands with lenses or layers of plastic clays. The soils are capable of safely supporting the design loads as they have a bearing capacity safety factor in excess of 3.

2.7.6.4 Intake Structure

The intake structure with the bottom of its mat foundation at el 52 bears on very firm and very dense clayey sands of the Duplin Formation. With a 5-ksf bearing pressure, the safety factor against bearing capacity failure is in excess of 4.

The stabilities of the intake structure and the river bluff immediately adjacent are shown by the following minimum safety factors calculated for various conditions:

Failure Mode	*Safety Factor*
Circular Arc - River banks adjacent to intake, pseudostatic,[a] a = 0.15 g	*1.8 min*
Circular arc through intake structure, static	*3.4 min*
Circular arc through intake structure, pseudostatic,[a] a = 0.15 g	*2.3 min*
Sliding through intake structure, static	*2.8 min*
Sliding through intake structure, pseudostatic,[a] a = 0.15 g	*2.1 min*

2.7.6.5 Main Stack

The pile foundation of the main stack bears on soils of the Duplin Formation which extend to ~ el 0. The upper portion of the Duplin Formation to elevations varying from 68 to 74 consists of very firm to very dense clayey sands and very stiff to hard sandy clays with cemented layers and inclusions. Below ~ el 71, the Duplin Formation may be divided into 3 significant strata. The first is soft to firm plastic clay with fine sand layers and inclusions. The thickness of this plastic clay zone varies from ~ 9 to 14 ft. Beneath the plastic clay lies a 7- to 10-ft-thick zone of loose to firm clayey sand. The lower portion of the Duplin Formation below el 55 and extending to ~ el 0 consists of very stiff to very dense clayey sands with scattered hard clay inclusions and occasional zones of firm to very firm clayey sands.

The bearing strata for piles consist of the dense sands below el 50. Static analysis indicates that the 14-in. H sections develop 100-ton capacity when driven to ~ el +20.

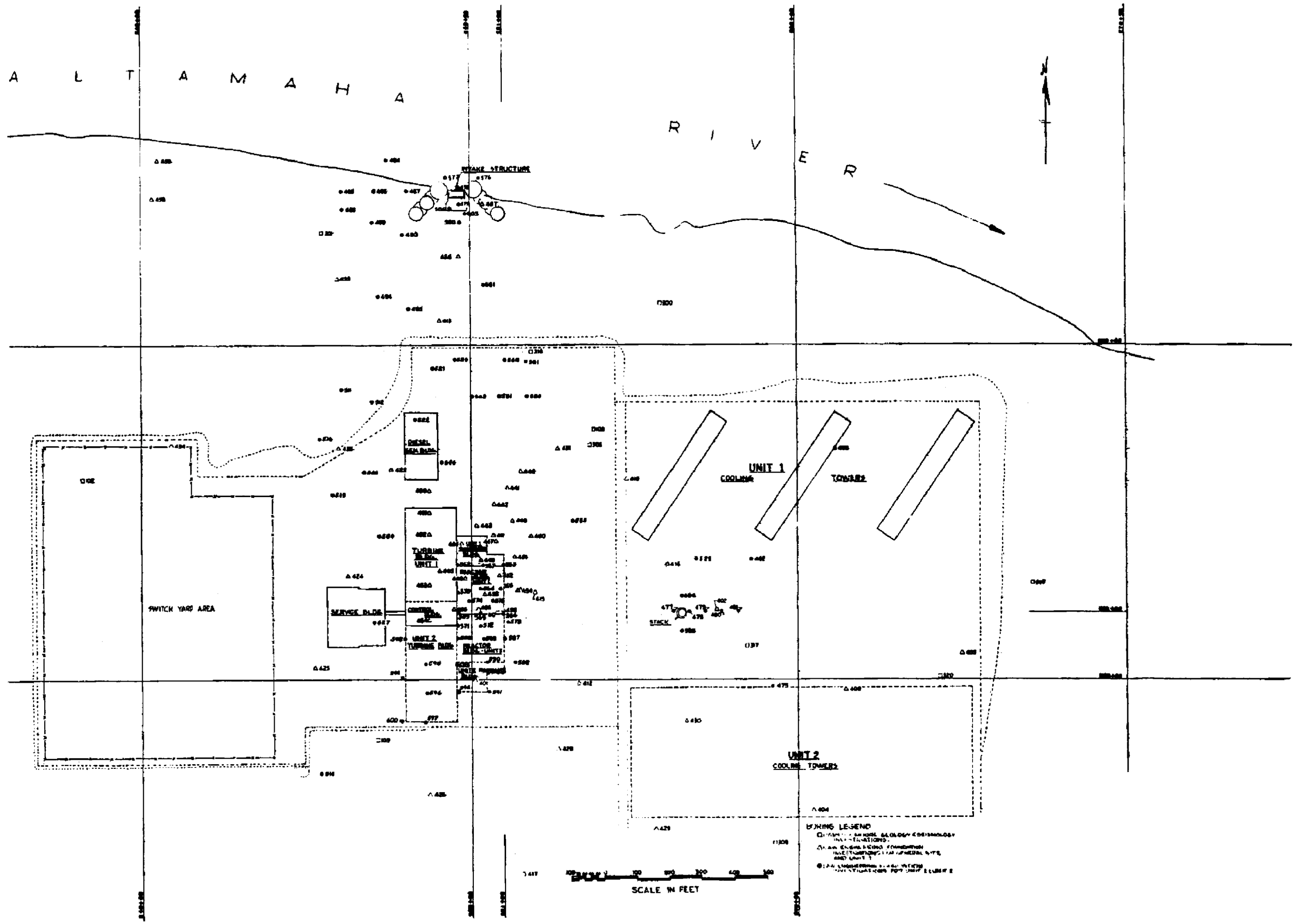
2.7.6.6 Diesel Generator Building

The diesel generator building, with its spread mat foundation at el 125, bears on very dense clayey fine to medium sand with some clay layers which extend to ~ el 120. Between elevations 120 and 70 are very dense medium to fine clayey sand with scattered layers and inclusions of very hard cemented clay and dense sands. The foundation pressure is < 3 ksf.

a. Earthquake forces considered to be equivalent static forces as suggested by N. M. Newmark in "The Effects of Earthquakes on Dams and Embankments," Geotechnique, Vol. 15, No. 2, June 1965.

2.7.7 LIQUEFACTION POTENTIAL

Within the area of the principal structures, there are no soils susceptible to liquefaction when subjected to the stress condition imposed by the design or design basis earthquake (DBE). For verification, dynamic triaxial tests were performed on typical samples from the site and plant area. These samples were tested under simulated in situ stress conditions comparable to the proposed DBE. The penetration resistance of the sand zones are much higher (much denser soil) than the sands that have been liquefied in areas where this phenomenon has been observed. In most cases, 15 to 25% of the sands at the site pass through the No. 200 sieve. This shows the soils are not truly cohensionless and are not susceptible to liquefaction. Also, the foundation soils are at least 13 million years old (Miocene) and are highly preconsolidated; whereas, in the areas where liquefaction has occurred, the soils have been recent alluvium, glacial outwash, or loose manmade fills.



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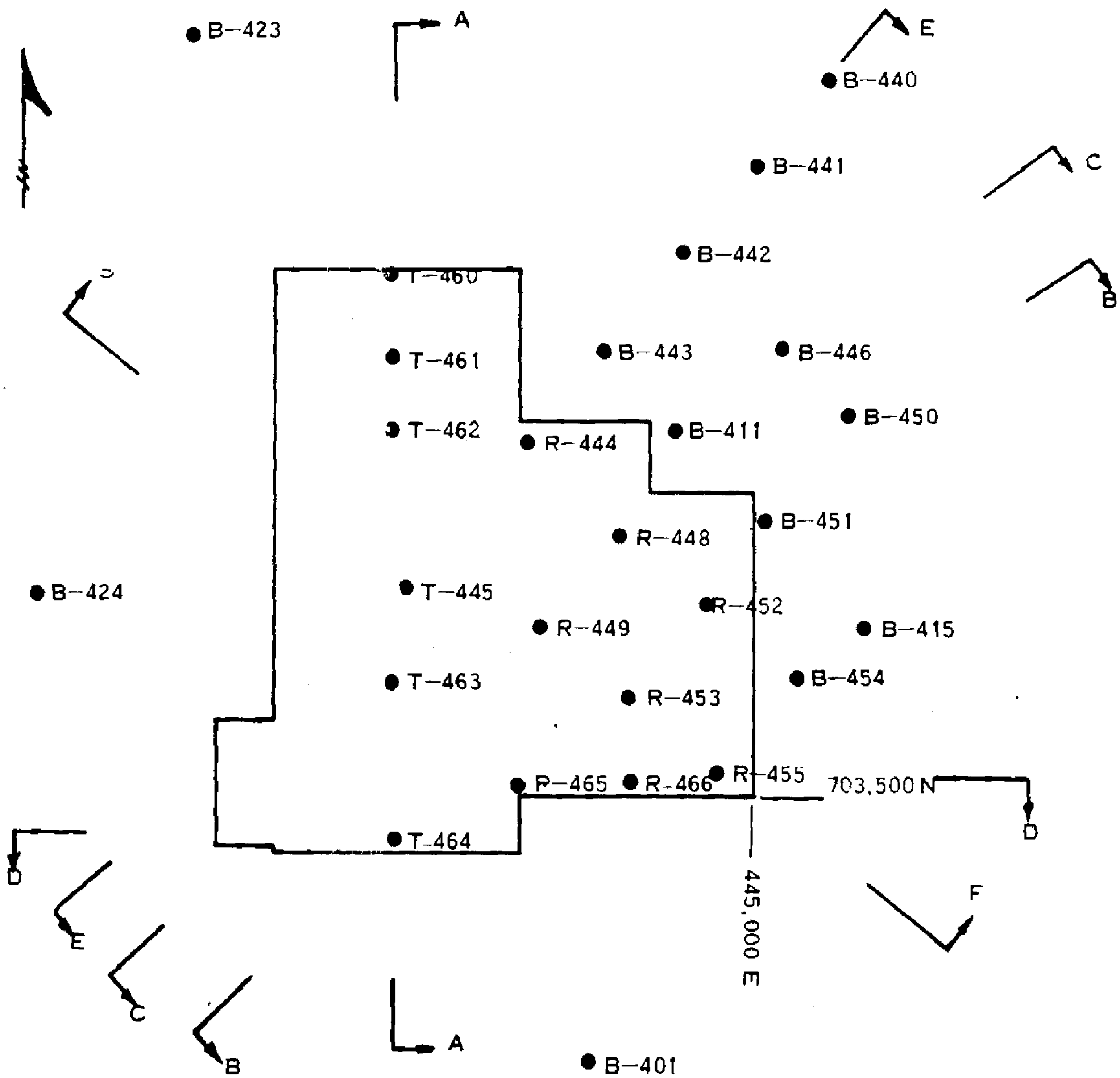
FOUNDATION BORINGS – LOCATION PLAN

FIGURE 2.7-1



Scale 1" = 100'

BORINGS SHOWN ON THIS PLAN

401
411
423 - 424
440 - 455
460 - 466

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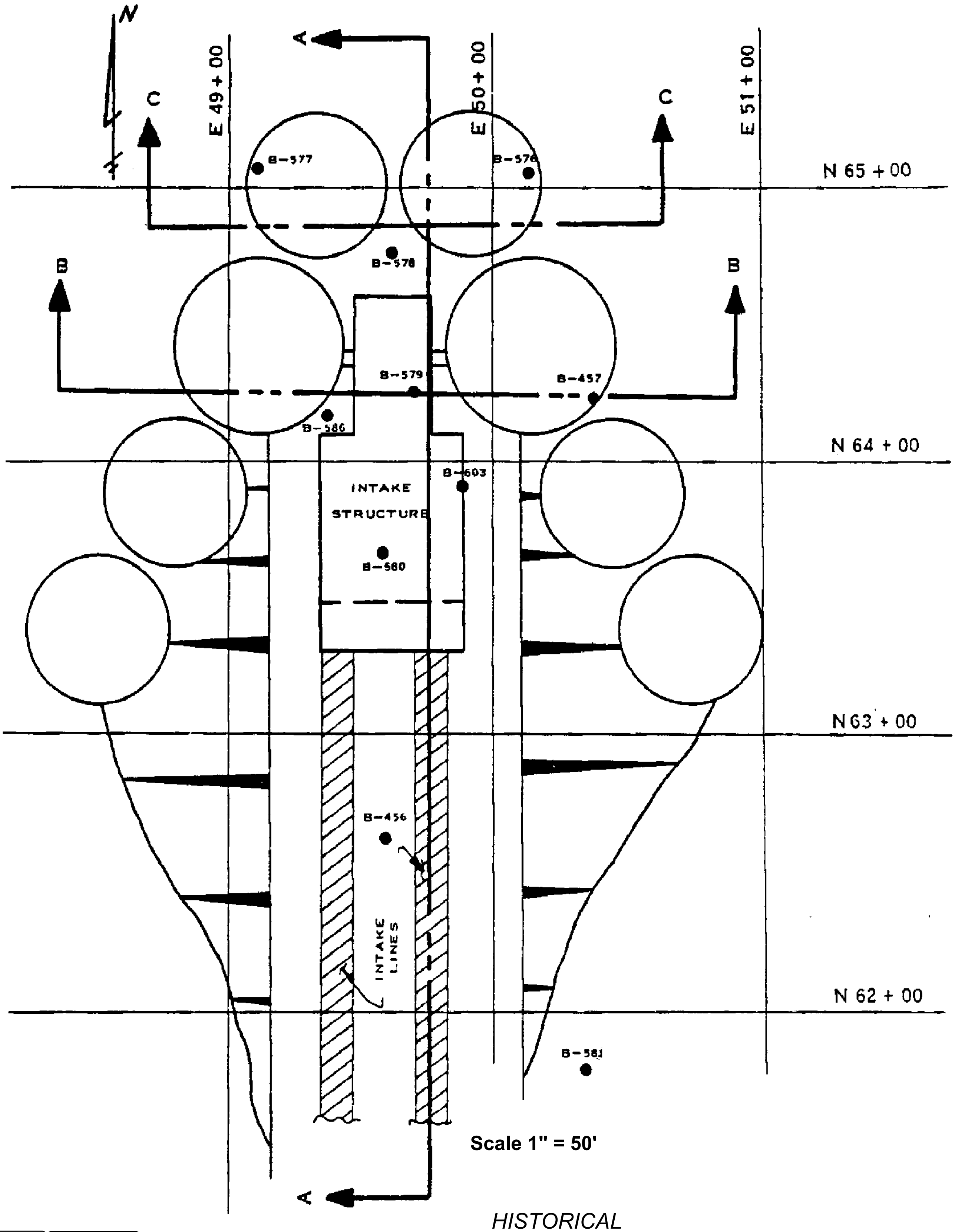
POWER HOUSE BORING PLAN

FIGURE 2.7-2



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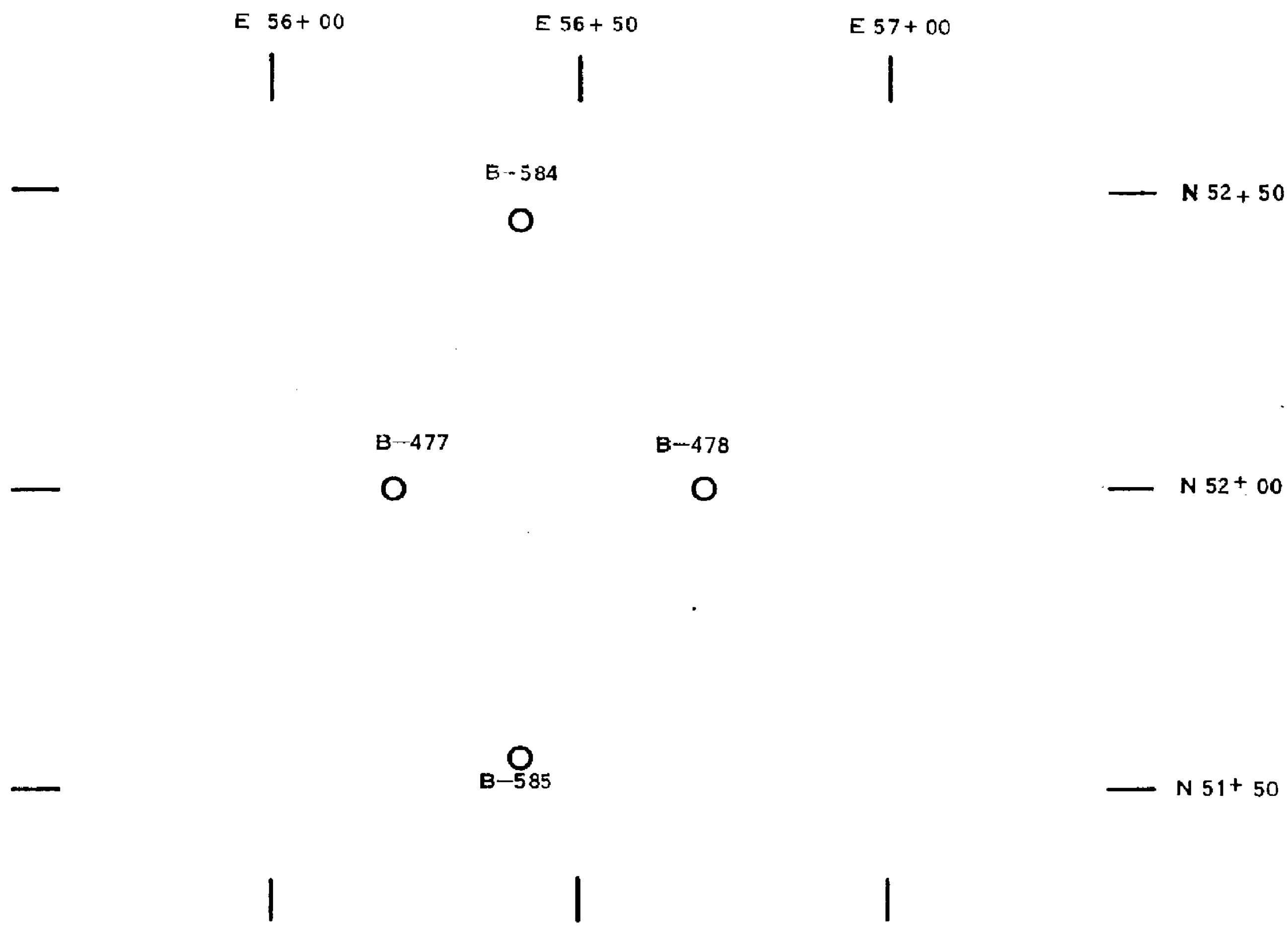
INTAKE STRUCTURE BORING PLAN

FIGURE 2.7-3



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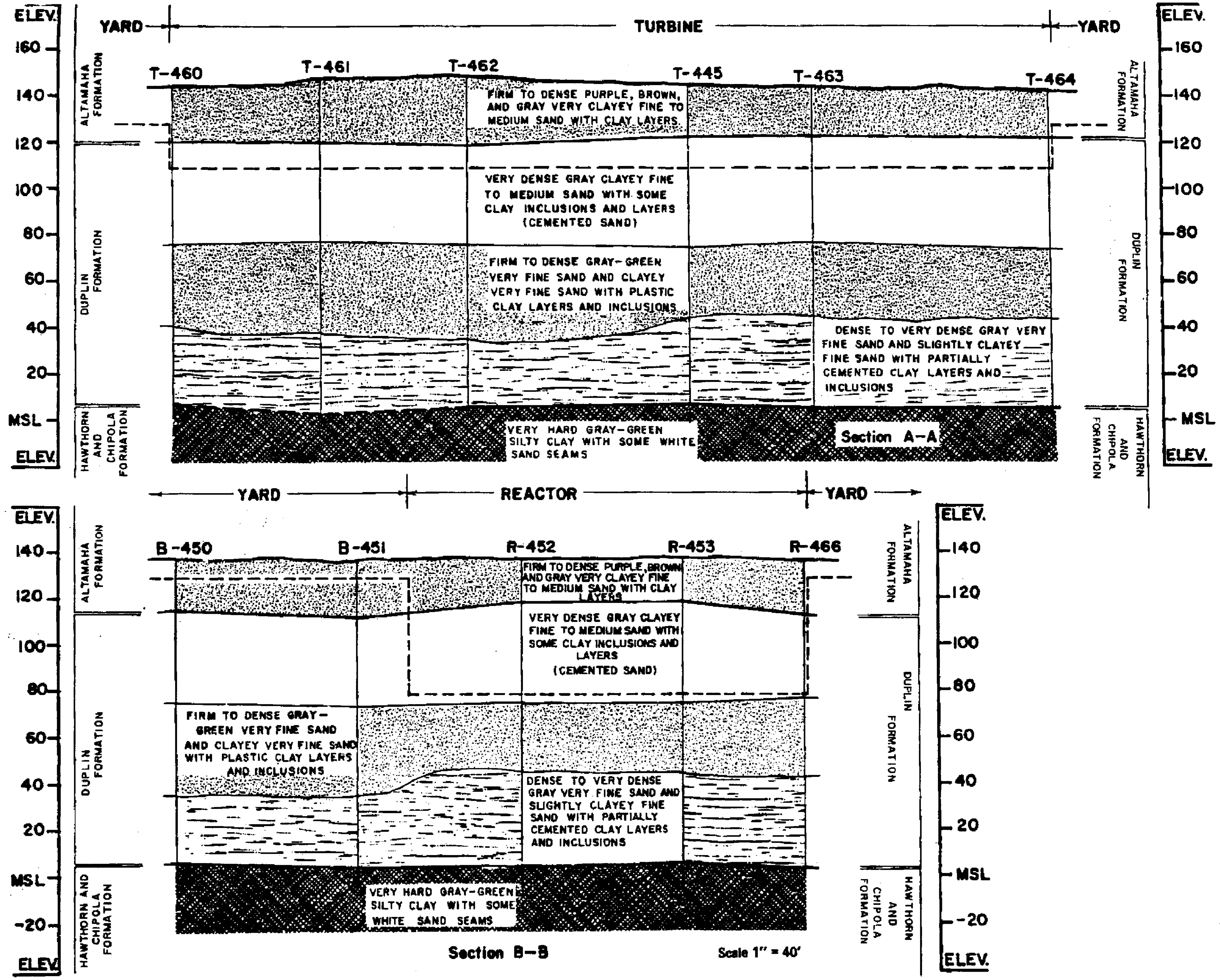
SOUTHERN COMPANY *Energy to Serve Your World®*	**SOUTHERN NUCLEAR OPERATING COMPANY** **EDWIN I. HATCH NUCLEAR PLANT** **UNIT 1**	STACK AREA BORING PLAN FIGURE 2.7-4



HISTORICAL

REV 19 7/01

ACAD 1020705

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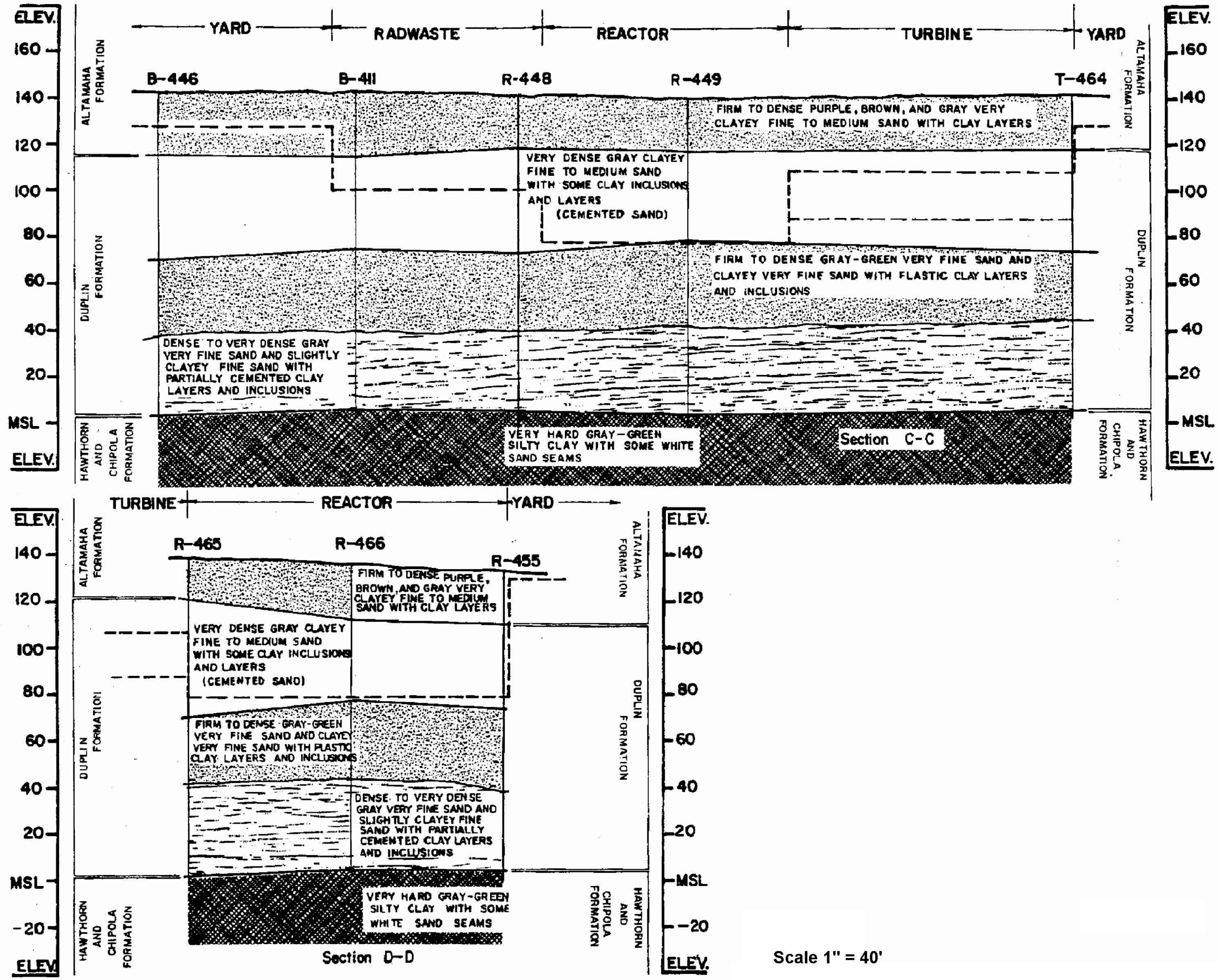
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES - POWER HOUSE AREA
SECTIONS A-A AND B-B

FIGURE 2.7-5



ACAD 1020720

HISTORICAL

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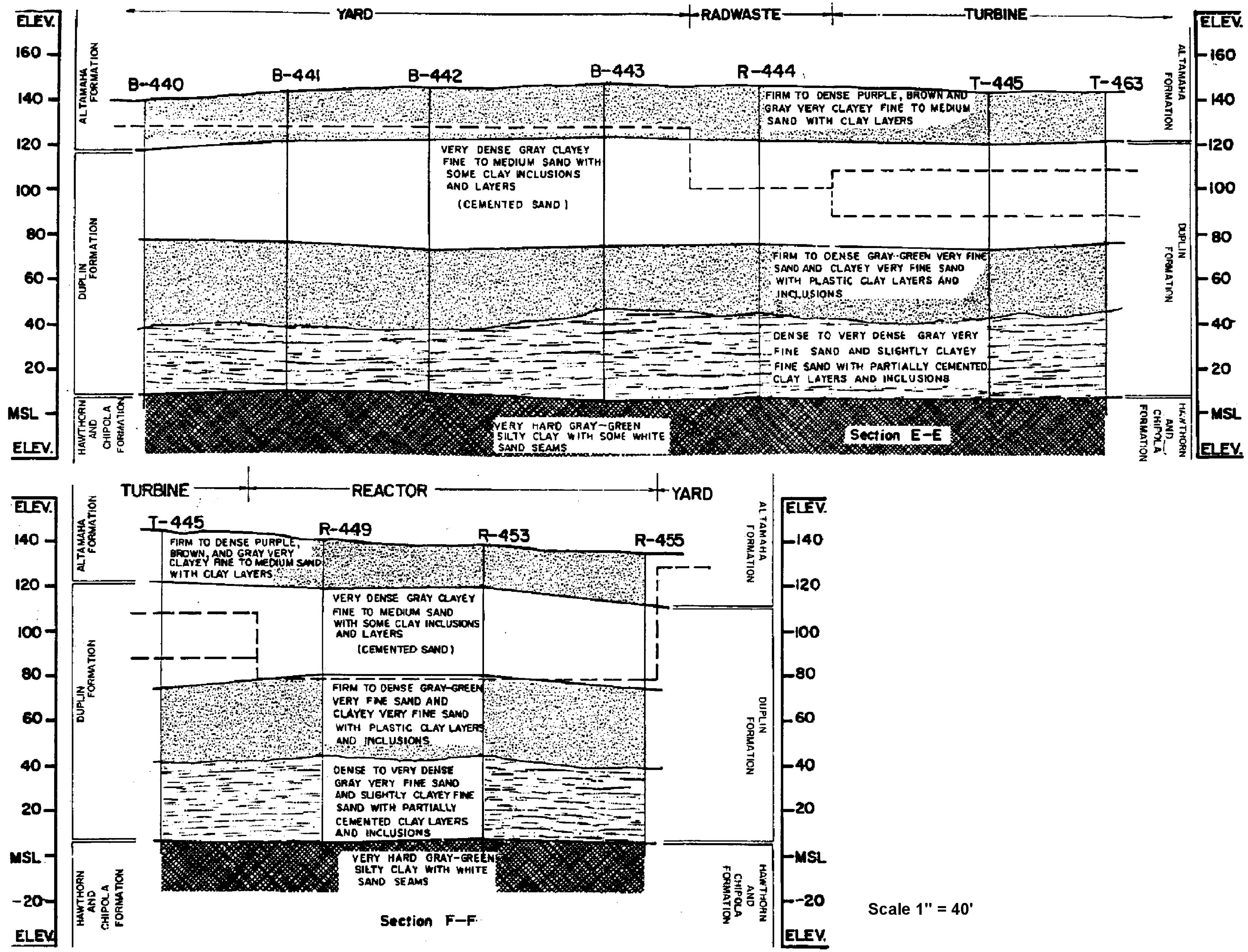
UNIT 1

SUBSURFACE PROFILES - POWER HOUSE AREA
SECTIONS C-C AND D-D

FIGURE 2.7-6



Scale 1" = 40'

ACAD 1020707

HISTORICAL

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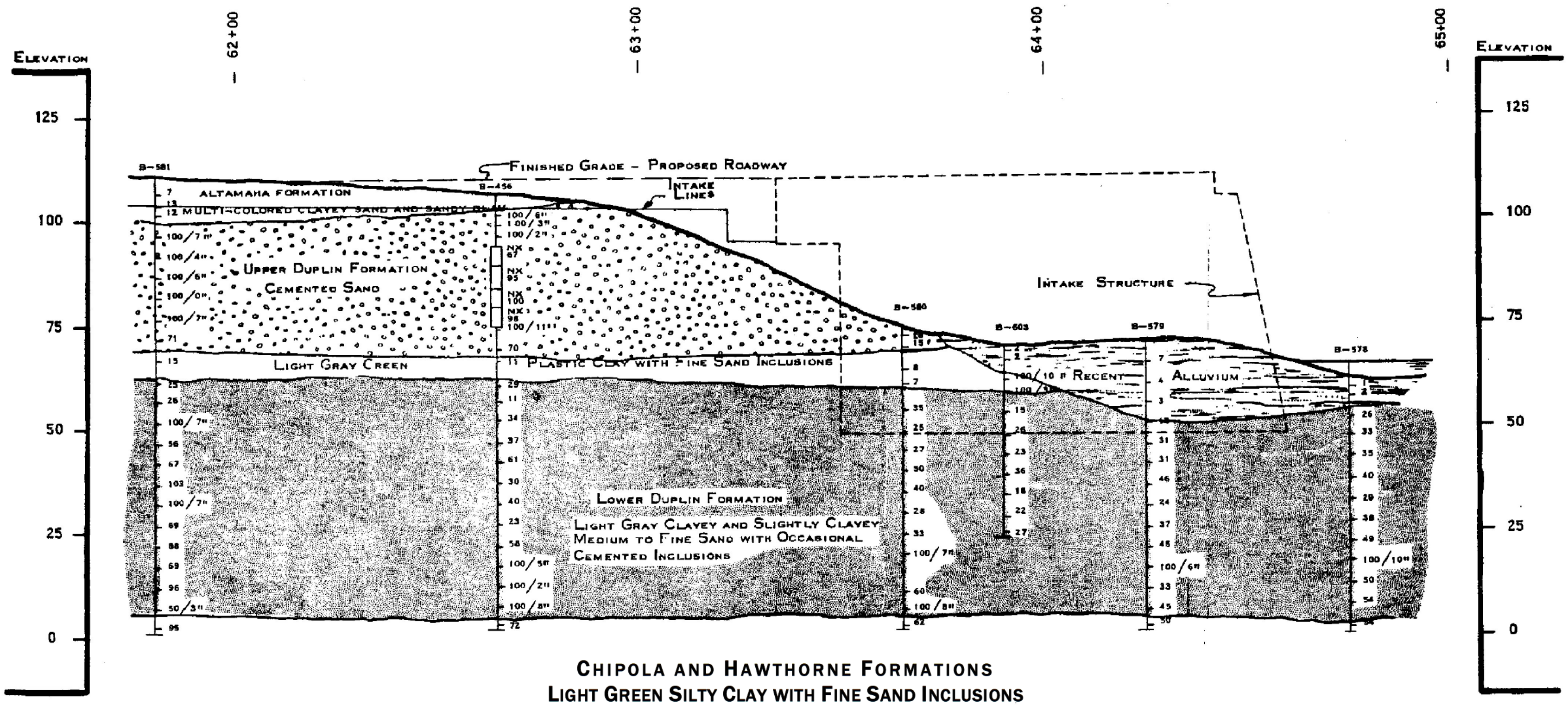
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES - POWER HOUSE AREA
SECTIONS E-E AND F-F

FIGURE 2.7-7



CHIPOLA AND HAWTHORNE FORMATIONS
LIGHT GREEN SILTY CLAY WITH FINE SAND INCLUSIONS
SECTION A-A

Scale 1" = 25'

ACAD 1020708

HISTORICAL

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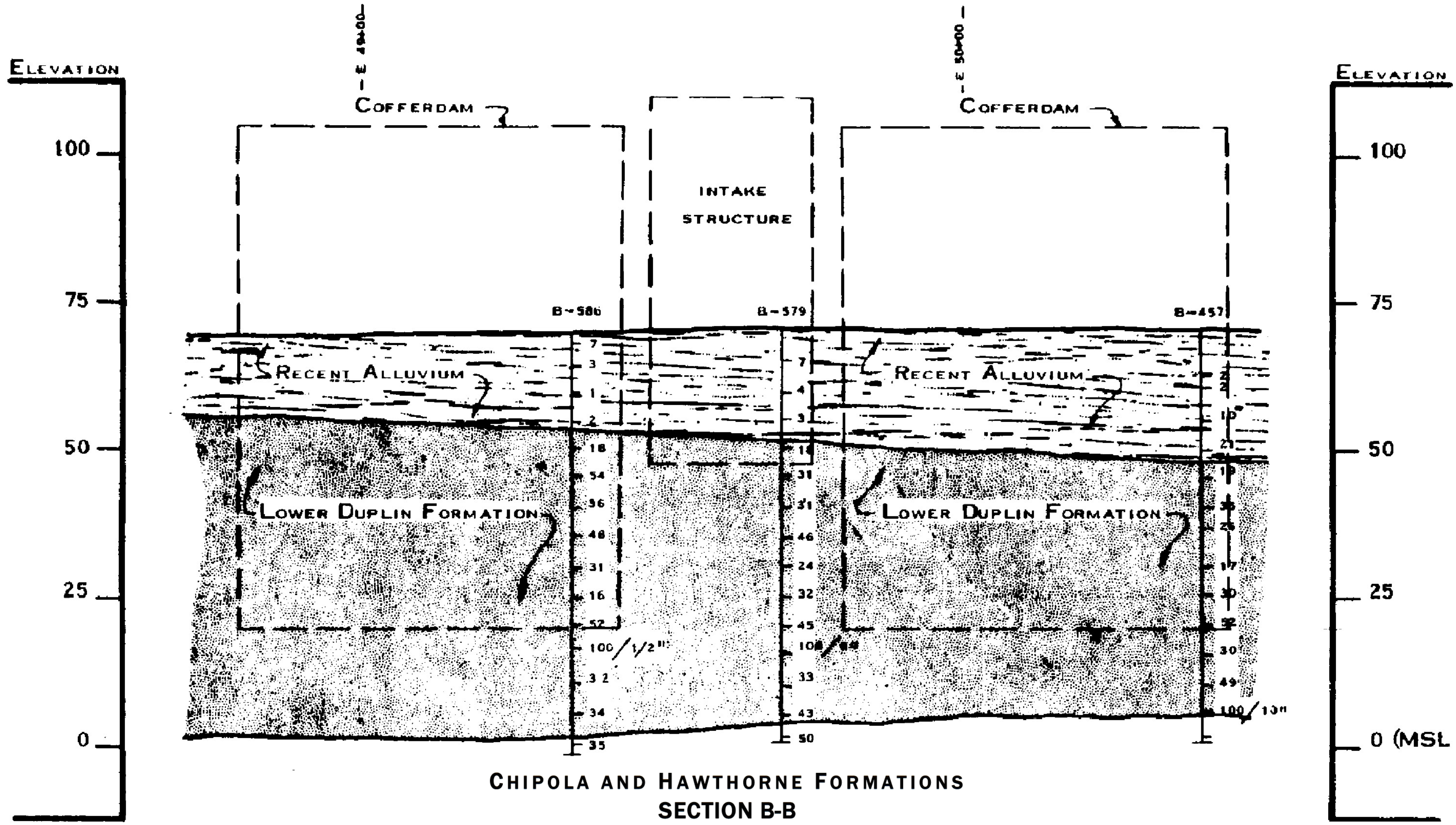
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES -
INTAKE STRUCTURE AREA
SECTION AA

FIGURE 2.7-8



Scale 1" = 25'

ACAD 1020709

HISTORICAL

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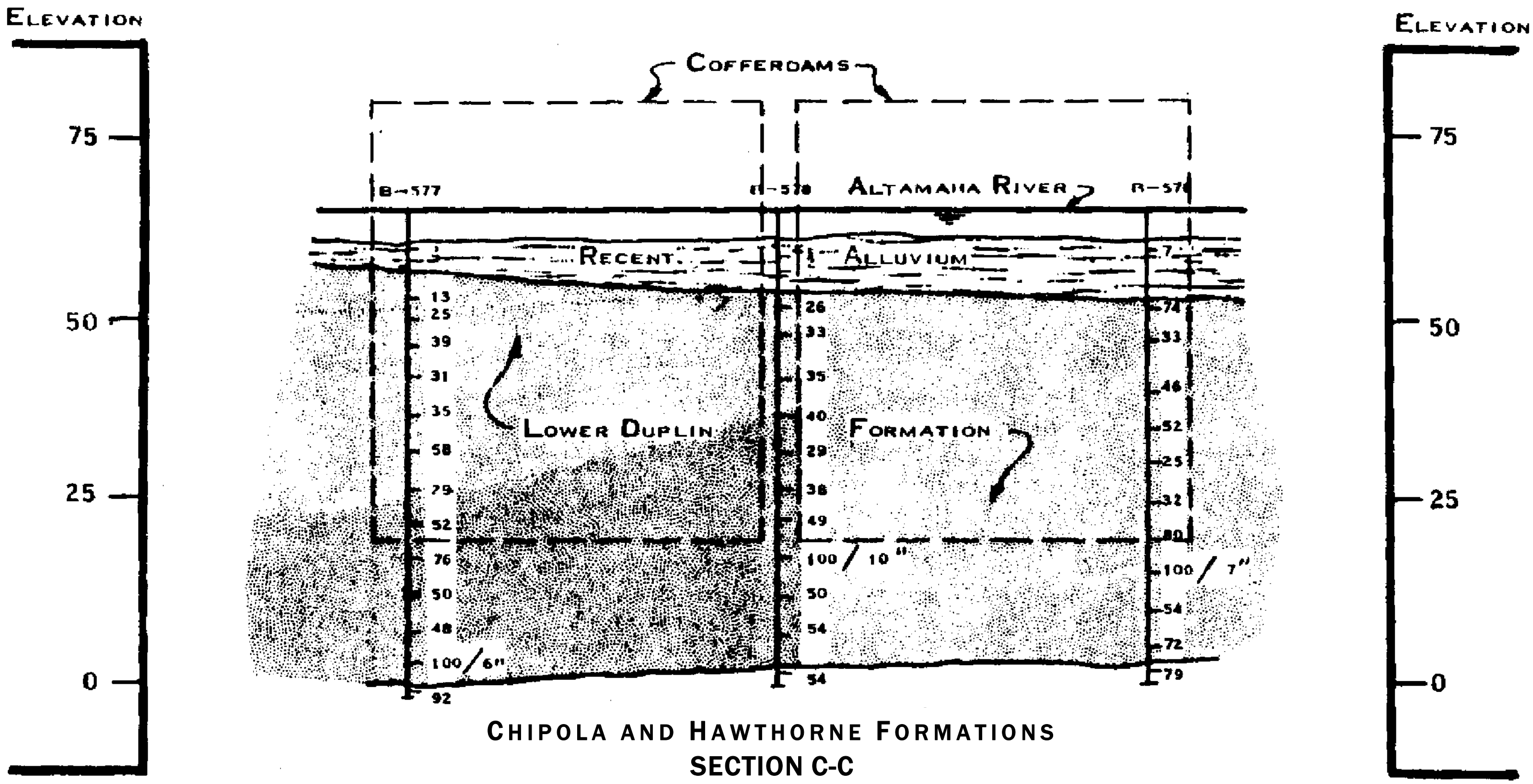
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES
INTAKE STRUCTURE AREA
SECTION B-B

FIGURE 2.7-9



SECTION C-C

ACAD 1020710

HISTORICAL

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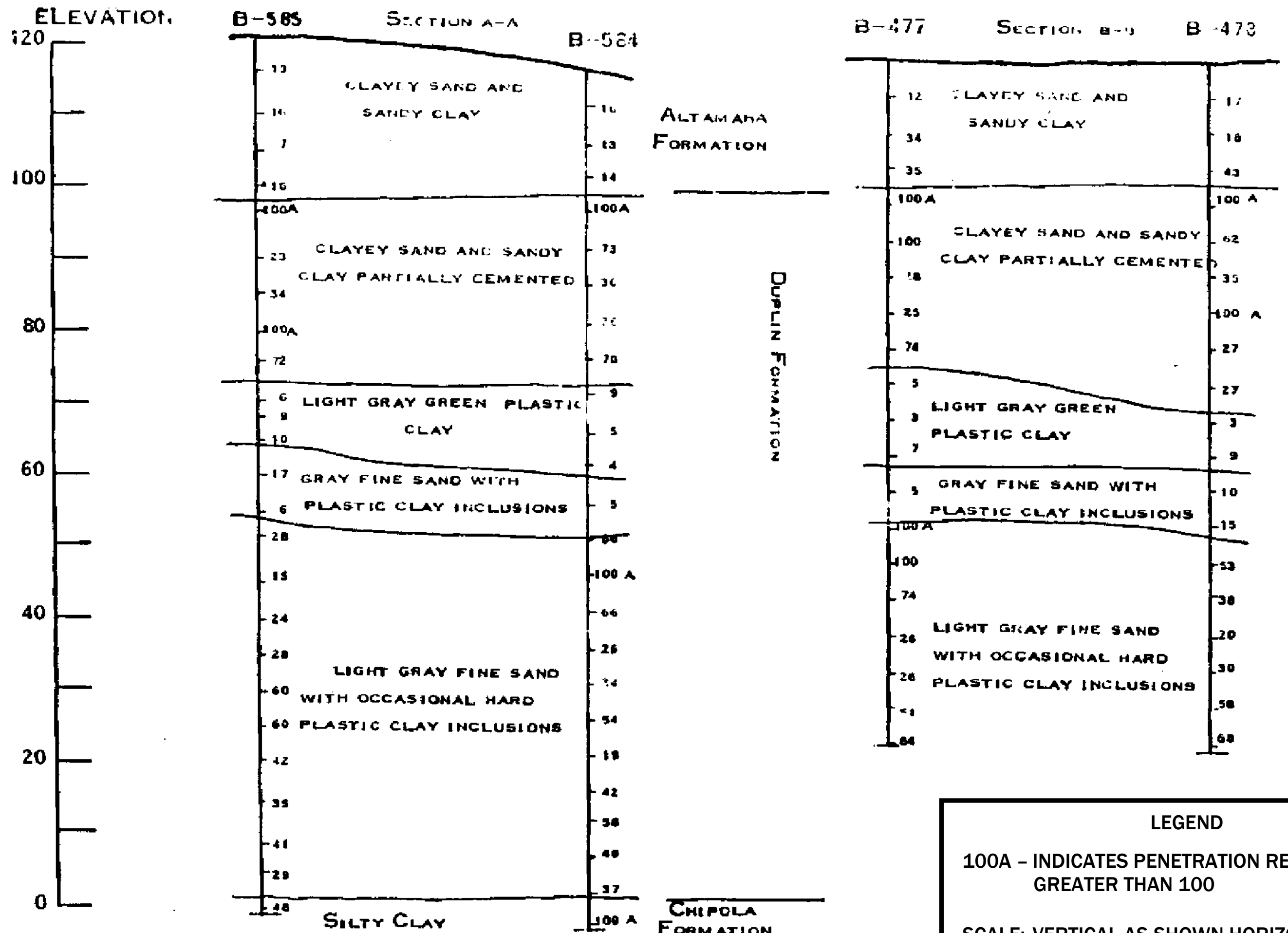
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES
INTAKE STRUCTURE AREA
SECTION C-C

FIGURE 2.7-10



LEGEND

100A – INDICATES PENETRATION RESISTANCE GREATER THAN 100

SCALE: VERTICAL AS SHOWN-HORIZONTAL-NONE

ACAD 1020711

HISTORICAL

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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

SUBSURFACE PROFILES
MAIN STACK AREA
SECTIONS A-A AND B-B

FIGURE 2.7-11

2.8 EXCAVATION AND REPLACEMENT OF BACKFILL FOR THE INTAKE STRUCTURE BURIED PIPING AND CONCRETE DUCTS

See section 2A.9 of the HNP-2-FSAR.

3.0 REACTOR

3.1 SUMMARY DESCRIPTION

A summary description of the reactor, and the systems and subsystems required for maintaining the fuel barrier and controlling core reactivity is provided in HNP-2-FSAR section 4.1, Reactor Summary Description.

3.2 FUEL MECHANICAL DESIGN

A description of the fuel mechanical design is provided in HNP-2-FSAR subsection 4.2.1, Fuel System Design.

3.3 REACTOR VESSEL INTERNALS MECHANICAL DESIGN

A description of the reactor vessel internals mechanical design is provided in HNP-2-FSAR subsection 4.2.2, Reactor Core Support Structures and Internals Mechanical Design.

3.4 REACTIVITY CONTROL MECHANICAL DESIGN

A description of the reactivity control system mechanical design is provided in HNP-2-FSAR subsection 4.2.3, Reactivity Control System.

3.5 CONTROL ROD DRIVE HOUSING SUPPORTS

A description of the CRD housing supports design is provided in HNP-2-FSAR section 4.5, Control Rod Drive Housing Supports.

3.6 NUCLEAR DESIGN

A description of the nuclear design is provided in HNP-2-FSAR section 4.3, Nuclear Design, and supplement 4A, Initial Core.

3.7 THERMAL AND HYDRAULIC DESIGN

A description of the thermal and hydraulic design is provided in HNP-2-FSAR section 4.4, Thermal and Hydraulic Design.

3.8 STANDBY LIQUID CONTROL SYSTEM

A description of the standby liquid control system design is provided in HNP-2-FSAR paragraph 4.2.3.4, SLCS.

4.0 REACTOR COOLANT SYSTEM

4.1 SUMMARY DESCRIPTION

This section describes those systems and components that form the major portions of the nuclear system process barrier. These systems and components contain or transport the fluids coming from or going to the reactor core.

Section 4.2 describes the reactor vessel and the various fittings with which other systems are connected to the vessel. The major safety consideration for the reactor vessel is concerned with the ability of the vessel to function as a radioactive material barrier. Various combinations of loading are considered in the vessel design. The vessel meets the requirements of various applicable codes and criteria. The possibility of brittle fracture is considered, and suitable design and operational limits are established that avoid conditions where brittle fracture is possible.

The reactor recirculation system provides coolant flow through the core. Adjustment of the core coolant flowrate changes reactor power output, thus providing a means of responding to plant load demand without adjusting control rods. The recirculation system is designed to provide a slow coastdown of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

The pressure relief system protects the nuclear system process barrier from damage due to overpressure. To protect against overpressure, pressure-operated relief valves are provided that can discharge steam from the nuclear system to the primary containment. The pressure relief system also acts to automatically depressurize the nuclear system in the event of a loss-of-coolant accident (LOCA) in which the high-pressure coolant injection system fails to maintain reactor water level. Depressurization of the nuclear system allows low-pressure emergency core cooling subsystems to supply enough cooling water to adequately cool the fuel.

The main steam line flow restrictors are venturi-type flow devices. One restrictor is installed in each main steam line inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break (MSLB) outside the primary containment. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time required for the main steam isolation valves (MSIVs) to close. This action protects the fuel barrier.

The MSIVs automatically close to isolate the nuclear system process barrier in the event a pipe break occurs downstream of the valves. This action limits the loss of coolant and the release of radioactive material from the nuclear system. Two isolation valves are installed on each main steam line; one is located inside and the other is located outside the primary containment. In the event that a MSLB occurs inside the primary containment, closure of the isolation valve outside the containment acts to seal the primary containment itself.

The reactor core isolation cooling system provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system may be started manually by the operator or automatically upon receipt of a low reactor water level signal. Water is pumped to the core by a turbine pump driven by reactor steam.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. Another operational mode of the RHR system is low-pressure coolant injection (LPCI). LPCI operation is an engineered safeguard for use during a LOCA. This operation is described in chapter 6, Emergency Core Cooling System. Another mode of RHR system operation allows heat to be removed from the primary containment following a LOCA.

The reactor water cleanup system functions to maintain the required purity of reactor coolant by circulating coolant through a system of filter-demineralizers.

Section 4.10 establishes the limits on nuclear system leakage inside the primary containment so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

4.2 REACTOR VESSEL AND APPURTENANCES MECHANICAL DESIGN

4.2.1 POWER GENERATION OBJECTIVE

The reactor vessel design objective is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the fuel. Design of the reactor vessel and appurtenances provides both the means for attaching pipelines to the reactor vessel and for installing vessel internal components. The current safety analysis report(1) and reactor operating pressure increase (ROPI) project report(2) demonstrate that the HNP-1 reactor vessel can safely operate at a power level of 2804 MWt and 1060 psia.

4.2.2 POWER GENERATION DESIGN BASES

A. Location and design of the external and internal supports provided as an integral part of the reactor vessel are such that stresses in the reactor vessel and supports due to reactions at these supports are within American Society of Mechanical Engineers (ASME) Code limits.

B. Reactor vessel design lifetime is 40 years; however, aging management programs (HNP-2-FSAR subsections 18.1.2, 18.2.9, 18.2.12, 18.2.15, and 18.2.17) monitor the ongoing condition of the reactor vessel so that actions are taken to provide reasonable assurance that the vessel is capable of performing its intended function for 40 years and beyond.

C. Design of the reactor vessel and appurtenances allows for the accomplishment of a suitable program of inspection and surveillance.

4.2.3 SAFETY DESIGN BASES

A. The reactor vessel and appurtenances are designed to withstand adverse combinations of loading and forces resulting from operation under normal and accident conditions.

B. To minimize the possibility of brittle-fracture failure of the nuclear system process barrier, the following is required:

   1. The initial ductile-brittle RT_{NDT} of materials used in the reactor vessel is known by references or established empirically.

   2. Expected shifts in RT_{NDT} during design service life due to conditions, such as neutron flux, are determined and employed in the reactor vessel design.

   3. Operation margins observed with regard to the adjusted reference temperature; i.e., initial RT_{NDT} + shift in RT_{NDT} are designated for each mode of operation.

4.2.4 DESCRIPTION

4.2.4.1 Reactor Vessel

The reactor vessel is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction (drawing nos. SX-16121 through SX-16123). The reactor vessel is designed and fabricated for a useful life of 40 years, based upon the specified design and operating conditions. Aging management programs (HNP-2-FSAR subsections 18.2.1, 18.2.9, 18.2.12, 18.2.15, and 18.2.17) monitor the ongoing condition of the reactor vessel so that actions are taken to provide reasonable assurance that the vessel is capable of performing its intended function for 40 years and beyond. The vessel is designed, fabricated, inspected, tested, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III, its interpretations, and applicable requirements for Class A vessels, as defined therein. Design of the reactor vessel and its support system meets Class 1 seismic requirements. Ten stress cycles of the operating basis earthquake seismic amplitude are considered in the usage evaluation of the reactor pressure vessel (RPV). The materials used in the design and fabrication of the RPV are shown in table 4.2-1. Typical reactor vessel data are included as table 4.2-2.

The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low-alloy steel plate which is clad on the interior with stainless steel weld overlay. The plates and forgings are ultrasonically tested and magnetic particle tested over 100% of their surfaces after forming and heat treatment. Preheat of vessel plate and forgings is maintained during welding until the weld joints are post-weld-heat treated. Full-penetration welds are used at all joints, including nozzles, throughout the vessel; nozzles of < 3-in. nominal size and the control rod drive (CRD) housing to stub tube welds are exempted.

Although little corrosion of carbon or low-alloy steels occurs at temperatures of 500 to 600°F, higher corrosion rates occur at temperatures around 140°F. The 0.125-in. minimum thickness stainless steel cladding over vessel walls and bottom head provides the necessary corrosion resistance during reactor shutdown and helps to maintain water clarity during refueling operations. Since the vessel top head is exposed to a saturated steam environment throughout its operating lifetime, stainless steel cladding is not required over its interior surfaces. Exterior, exposed ferritic surfaces of parts which contain pressure have a minimum corrosion allowance of 1/32 in. The interior surfaces of the top head and all carbon and low-alloy steel nozzles exposed to the reactor coolant have a corrosion allowance of 1/16 in. Calculation of the nozzle corrosion allowance represents a time-limited aging analysis (HNP-2-FSAR section 18.5) which GE demonstrated to be valid for the renewed license term. The vessel shape is designed to limit coolant retention pockets and crevices.

The vessel top head is secured to the reactor vessel by studs and nuts which are designed to be tightened with a stud tensioner. The vessel flanges are sealed with 2 concentric metal seal-rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including cold hydrostatic pressure testing at the pressure specified in the ASME Code and heating to operating pressure and temperature at a maximum rate of 100°F/h. To detect a lack of seal integrity, a 1-in. vent tap is provided in the area between the two seal-rings, and a monitor line is attached to the tap to provide an indication of leakage from the inner seal-ring seal.

The head and vessel flanges are low-alloy steel forgings. The sealing surfaces of the reactor vessel head and shell flanges are weld overlay clad with austenitic stainless steel, similar to that of the vessel, and consist of a minimum of two layers for a minimum of 0.25-in. total thickness after all machining, including the area under the seal grooves. The first layer is deposited with a composition equivalent to American Society of Testing Materials (ASTM) A-371, Type ER309; the second layer has a composition equivalent to ASTM A-371, Type ER308, except that the carbon content does not exceed 0.08%.

The vessel top head nozzles are provided with flanges with small groove facing. The drain nozzle is of the full-penetration weld design and extends below the bottom outside surface of the vessel. The recirculation inlet nozzles, located as shown on drawing nos. SX-16121 and SX-16122, feedwater inlet nozzles, and the core spray (CS) inlet nozzle all have thermal sleeves similar to those shown in the detail of figure 4.2-1. The CRD hydraulic system return nozzle has been capped and its thermal sleeve removed.

The vessel nozzles (figure 4.2-1) are low-alloy steel forgings made in accordance with ASME A-508. Nozzles of 3-in. nominal size or larger are full penetration welded to the vessel. Nozzles of $<$ 3-in. nominal size may be partial penetration welded, as permitted by the ASME Code, Section III. Nozzles which are partial penetration welded are nickel-chromium-iron forgings made in accordance with ASME SB-166 or ASME SB-167.

The nozzle for the core differential pressure and liquid control pipe is designed with a transition so that the stainless steel outer-pipe of the differential pressure and liquid control line (HNP-2-FSAR subsection 4.2.2, Reactor Core Support Structures and Internals Mechanical Design) can be socket welded to the inner end of the nozzle and so that the inner pipe passes through the nozzle. This design provides an annular region between the nozzle and the inner liquid control line to minimize thermal shock effects on the reactor vessel in the event that use of the standby liquid control system is required.

The jet pump instrumentation penetration seal is welded directly to the outer end of the jet pump instrumentation nozzle. The stainless steel recirculation loop piping (section 4.3, Reactor Recirculation System) is welded to the outer end of the recirculation outlet nozzle. The main steam line piping is welded to the outer end of the steam outlet nozzle. The piping attached to the vessel nozzle is designed, installed, and tested in accordance with the requirements of appendix A.

Thermocouple pads are located on the exterior of the vessel. At each thermocouple location, two 3/4-in. diameter pads are provided: an end pad to hold the end of a 3/16-in. diameter thermocouple and a clamp pad equipped with a set screw to secure the thermocouple.

4.2.4.1.1 Materials Considerations

4.2.4.1.1.1 Fracture Toughness. See HNP-2-FSAR subsection 5.2.4 for a description of HNP-1 fracture toughness.

4.2.4.1.1.2 Reactor Material Surveillance. See HNP-2 FSAR subsection 5.2.4 for a description of HNP-1 reactor material surveillance program requirements.

Further information and historical references regarding vessel materials, neutron fluence, and RT_{NDT} are also given in appendix R.

4.2.4.1.1.3 Boiling Water Reactor Vessel and Internals Program. See HNP-2-FSAR subsection 18.2.15 for a description of the program that manages the effects of aging on the reactor vessel and the reactor internal components.

4.2.4.1.1.4 Intergranular Stress Corrosion Cracking. The precautions taken to avoid significant sensitization of austenitic stainless steel during heat treatments and welding operations for core structural load bearing members and component parts of the reactor coolant pressure boundary are:

A. The carbon content of the cladding (on internal RPV surfaces) is limited to 0.08% maximum.

B. Internal stainless steel structural members subject to furnace stress relief are specified to have a carbon content < 0.035%, or to be clad afterwards.

C. Stainless steel nozzle ends are not exposed to furnace stress relief of the vessel, nor to any prolonged heating above 800°F. Those safe ends that had gone through furnace stress relief were replaced.

D. All welding and inspection procedures are reviewed and approved by GE-APED prior to use in fabrication. This review includes adequacy of the technique in minimizing/detecting sensitization damage.

4.2.4.2 Shroud Support

The reactor vessel shroud is a cylindrical shell that surrounds the reactor core assembly and provides a barrier to separate the upward core flow from the downcomer annulus flow. The shroud support is a circular plate welded to the vessel wall and is designed to carry the weight of the shroud, the steam separators, and the jet pump system. Stresses due to reactions at the shroud support are within appropriate ASME Code limits for normal, upset, emergency, and faulted loading conditions.

Design of the shroud support also takes into account the restraining effect of components attached to the support, and weight and earthquake loadings. The vessel shroud support and other internal attachments (jet pump riser support pads, guide rod brackets, steam dryer support brackets, dryer holddown brackets, feedwater sparger brackets, and CS brackets) are shown in HNP-2-FSAR figure 4.1-1.

4.2.4.3 Reactor Vessel Support Assembly

The reactor vessel is supported laterally and vertically. Bracing makes it as rigid as possible without impairing the movements required for thermal expansion. Where thermal requirements prohibit the use of rigid supports, spring anchors or hydraulic snubbers are used; they resist earthquake forces while allowing sufficient flexibility for thermal expansion.

The reactor vessel support assembly consists of a ring girder and the various bolts, shims, and set screws necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The reinforced concrete support pedestal is constructed as an integral part of the building foundation. Steel anchor bolts are set in the concrete, with their threads extending above the surface. The anchor bolts extend through the ring girder bottom flange. High-strength bolts are used to secure the flange of the reactor vessel support skirt to the top flange of the ring girder. The ring girder is fabricated of ASTM A-36 structural steel according to American Institute of Steel Construction (AISC) Specifications.

4.2.4.4 Vessel Stabilizers

Vessel stabilizers are provided to transmit seismic and jet reaction forces to supporting structures. They also limit horizontal vibration. The vessel stabilizers connect the reactor vessel to the top of the shield wall surrounding the vessel. Full-penetration welds attach four stabilizer brackets to the reactor vessel at evenly spaced locations around the vessel below the flange. Each vessel stabilizer consists of a stabilizer rod, threaded at the ends; springs, washers, a nut, a plate, and a bumper bracket with tapered shims. The stabilizers are attached to each bracket and apply tension in opposite directions. The stabilizers are evenly preloaded with tensioners to the values of the residual loads. The stabilizers are designed to permit radial and axial vessel expansion.

4.2.4.5 Refueling Bellows

The refueling bellows forms a seal between the reactor vessel and the surrounding drywell to permit flooding of the space (reactor well) above the vessel during refueling operations. The refueling bellows assembly (HNP-2-FSAR figure 4.1-1) consists of a Type 304 stainless steel bellows, a backing plate, a spring seal, and a removable guard ring. The backing plate surrounds the outer circumference of the bellows to protect it and is equipped with a tap for testing and for monitoring leakage. The self-energizing spring seal is located in the area between the bellows and the backing plate. The seal is designed to limit water loss in the event of a bellows rupture; should this occur, the seal makes a tight fit to the backing plate when subjected to full hydrostatic pressure. The guard ring attaches to the assembly and protects the inner circumference of the bellows. To permit inspection of the bellows the guard ring can be removed from above. The assembly is welded to the reactor bellows support skirt and the reactor well seal bulkhead plate. The reactor bellows support skirt is welded to the reactor vessel shell flange, and the reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. Six watertight hinged covers are bolted in place on the bulkhead plate for normal refueling operation. For normal operation, these covers are opened and removable air supply ducts and air return ducts permit circulation of ventilation air in the region above the reactor well seal.

4.2.4.6 CRD Housings

The CRD housings are inserted through the CRD penetrations in the reactor vessel bottom head and are welded to the stub tubes extending into the reactor vessel. Each housing transmits a number of loads to the bottom head of the reactor. These loads include the weight of a control rod and CRD, which are bolted to the housing from below (HNP-2-FSAR subsection 4.2.3), the weight of a control rod guide tube, one four-lobed fuel support piece, and the four fuel assemblies which rest on the top of the fuel support piece (HNP-2-FSAR subsection 4.2.2). The housings are fabricated of Type 304 austenitic stainless steel.

4.2.4.7 CRD Housing Supports

The CRD housing support is designed to prevent a nuclear transient in the unlikely event that there is a CRD housing failure. This device consists of a grid structure located below the reactor vessel from which housing supports are suspended. The supports allow only slight movement of the CRD or housing in the event of failure. The CRD housing support is discussed in detail in HNP-2-FSAR section 4.5.

4.2.4.8 Incore Neutron Flux Monitor Housings

The incore neutron flux monitor housings are inserted up through the incore penetrations in the bottom head of the reactor vessel and are welded to the inner surface of the bottom head. An incore flux monitor guide tube is welded to the top of each housing (HNP-2-FSAR subsection 4.2.2) and either a source range monitor/intermediate range monitor drive unit or a local power range monitor is bolted to the seal-ring flange at the bottom of the housing (section 7.5).

4.2.4.9 Reactor Vessel Insulation

The reactor vessel insulation has an average maximum heat transfer rate of ~ 0.2 Btu/h/ft^2/°F at the operating conditions of 550°F for the vessel and 135°F for the outside air. The drywell average air temperature limit for normal operation is ≤ 150°F. The maximum insulation thicknesses are ~ 4 in. for the upper head, 3 1/2 in. for cylindrical shell and nozzles, and 3 in. for the bottom head. The upper head insulation is designed to permit complete submersion in water during shutdown without loss of insulating material, contamination from the water, or adverse effect on the insulation efficiency of the insulation assembly after draining and drying.

4.2.5 SAFETY EVALUATION

The reactor vessel design pressure of 1250 psig is based on an analysis for margins required to provide a reasonable operating range; margins include additional allowances to accommodate transients above the operating pressure (~ 1038 psig at the level of the top head flange) without initiating operation of the safety valves. The design temperature for the reactor vessel (575°F) is based on the saturation temperature of water which corresponds to the design pressure.

To withstand external and internal loadings while maintaining a high degree of corrosion resistance, a high-strength carbon alloy steel is used as the base metal and an internal cladding of stainless steel is applied using weld overlay.

High fatigue usage components are selected to be in a thermal cycle tracking program to assure that such components will continue to meet the fatigue cumulative usage factor (CUF) requirements of the ASME Code, Section III, design requirement value of less than or equal to 1.00. The thermal cycle tracking program records the pressure and temperature histories during plant transient events. A description of the component cyclic or transient limit program is provided in HNP-2-FSAR subsection 18.2.12.

The data are used to update these CUFs of the high fatigue components to assure reactor vessel component structural adequacy and ASME Code compliance based on actual plant duty. The components selected for monitoring on HNP-1 and HNP-2 are the RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles.

FatiguePro$_{TM}$ is used to determine the CUF for each of the limiting RPV components. In addition, a license renewal commitment includes evaluation of the locations identified in NUREG/CR-6260 using the applicable environmental fatigue correlations provided in NUREG/CR-6909. Four locations have been shown by analysis to have the highest CUF predictions over the life of the RPV. All other areas of the RPV have been analyzed to have a negligible effect on the fatigue of the RPV and thus are not monitored. The applicable RPV locations for Unit 1 are:

- Reactor vessel shell.
- Feedwater nozzle.
- Recirculation inlet nozzle.
- Closure studs

FatiguePro$_{TM}$ 3.0 is used to determine the fatigue Cumulative Usage Factor (CUF) for limiting components. This methodology is reflected in the fleet procedures for CUF monitoring and is performed at least once per operating cycle. The FatiguePro$_{TM}$ system implemented consists of Automated Cycle Counting (ACC) and Cycle Based Fatigue (CBF). ACC methodology uses plant instrumentation to determine plant events while the CBF methodology computes fatigue based on identified plant cycles. These two methodologies are used for the reactor pressure vessel (RPV) locations, as well as the Class 1 piping systems and containment/torus structure and attached piping.

CBF is computed in the FatiguePro$_{TM}$ system using per-cycle methodology or event-pairing. The Per-Cycle usage methodology computes fatigue usage for a component by determining a location-specific fatigue usage increment for each counted event, and then adding up those increments for all events in the cycle record. For a license Renewal commitment, evaluation of the locations identified in NUREG/CR-6260 have been performed using FatiguePro$_{TM}$, which incorporates the applicable environmental fatigue correlations provided in NUREG/CR-6909.

The reactor assembly design is such that the average annular distance from the outer most fuel assemblies to the inner surface of the reactor vessel is ~ 28.6 in. This annular volume, which contains the core shroud, the jet pump assemblies, and reactor coolant, serves to attenuate the fast neutron flux incident upon the reactor vessel wall.

The HNP-1 fluence model was developed using the BWRVIP developed Radiation Analysis Modeling Application (RAMA) Code which has been approved by the NRC as compliant with Regulatory Guide 1.190. The projected fluence calculated by this model is used to predict nil ductility temperature shits for plant operation out to the end of licensed operation (EOL). HNP-2-FSAR table 5.2-7, sheet 1 of 2 shows both the fluence and predicted shift. The EOL adjusted RT_{NDT} shift is calculated to be 149°F. With an initial RT_{NDT} in the limiting vessel plate material of -20°F, the resulting maximum RT_{NDT} of the vessel wall at EOL will be 129°F. This EOL RT_{NDT} is below the vessel annealing limit of 200°F in 10 CFR 50, Appendix G; thus, provisions for annealing are not necessary.

To produce brittle fracture at or below the RT_{NDT}, a stress of 5000 to 8000 psi is considered necessary, which corresponds to an operating coolant pressure of ~ 250 psig. The associated coolant and, hence, shell temperature would be of the order of 400°F. Therefore, during operation when pressure is dependent upon temperature, brittle failure of the vessel is not considered possible until the neutron fluence of the reactor vessel reaches a value of the order of 10^{20} nvt. This value is a factor of more than 50 times the maximum neutron fluence conservatively calculated during the lifetime of this plant.

In addition to meeting the minimum requirements of the ASME Boiler and Pressure Vessel Code, the following precautions and tests either assure a low initial RT_{NDT} of the reactor vessel material or reduce the sensitivity of the material to irradiation effects:

A. The material was selected and fabrication procedures were controlled to produce as fine a grain size as practical. It was an objective in fabrication to maintain a grain size of 5 or finer.

B. Pressure-containing and structural materials of carbon and low-alloy steel were impact tested in accordance with Paragraph N-330 of Section III, ASME Code. The RT_{NDT} values are no higher than those specified in HNP-2-FSAR table 5.2-9, and Charpy V-Notch test results met the appropriate minimum required ASME Code, Section III, values at the specified temperatures.

C. Dropweight impact tests were performed on each heat charge and heat treatment charge of all low-alloy steel plate material in its as-fabricated condition. The dropweight specimens were Type P-3 as specified in ASME E-208.

D. Dropweight impact tests were performed on the weld metal, the heat-affected zone of the base metal, and the base metal of the weld test plates simulating seams. If different welding procedures were used for nozzle welds, dropweight tests were performed on coupons similarly prepared. The RT_{NDT} test criteria for the weld and heat-affected zone of the base material were the same as for the unaffected base metal.

E. The actual RT_{NDT} of material opposite the fuel zone was determined. For each main closure flange forging, a minimum of one tensile, three Charpy V-Notch, and two dropweight specimens were tested from each of two locations ~ 180° apart on the flange.

Small carbon steel safe ends, from which dropweight specimens cannot be made, were exempt from dropweight testing.

Quality control methods used during the fabrication and assembly of the reactor vessel and appurtenances assure that design specifications are met.

The aging management aspects of the reactor pressure vessel materials surveillance program are further discussed in HNP-2-FSAR subsection 18.2.17.

4.2.6 INSPECTION AND TESTING

Inservice inspection was considered during the design of the reactor vessel and insulation to assure adequate working space and access for inspection. This is described in further details in appendix H.

The acceptance standards used for HNP-1 are those specified in Appendix IX to Section III of the 1968 ASME Boiler and Pressure Vessel Code.

The HNP-1 reactor vessel material surveillance program is described in HNP-2 FSAR subsection 5.2.4. Both HNP-1 and HNP-2 follow the BWRVIP Integrated Surveillance Program.

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1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," <u>NEDC-33085P</u>, GE Nuclear Energy, December 2002.

2. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

3. Structural Integrity Software Verification and Validation Report for Hatch Plant-Specific FatiguePro 3 Software. Report No. FP-HTCH-405.

4. Structural Integrity Cycle Counting and Cycle Based Fatigue Report for the Transient and Fatigue Monitoring System at the Hatch Electrical Generating Plant Unit 1.

5. Structural Integrity Hatch Unit 1 Feedwater Nozzle NB-3200 Analysis Report No. 1200964.304 Revision 0.

6. Structural Integrity Calculation Package 1001182.301, Rev. 2 “Cycle-Based Fatigue Development for Select Hatch Locations”.

7. GE report GPC-103-1, “Reactor Pressure Vessel Thermal Cycle Evaluation for Edwin I. Hatch Nuclear Power Station Units 1 and 2”, DRF: B11-00362, August 1986.

8. GE Letter GEH-042, “Hatch 1 and 2 Extended Power Uprate Cumulative Fatigue Usage Factor Formulas,” August 13, 1997.

9. GE-NE-523-103-0793, Rev. 0, “Fatigue Analysis for the Recirculation Inlet Nozzles and Main Closure Studs, Edwin I. Hatch Nuclear Power Station Unit 1, DRF: 137-0010-6.

TABLE 4.2-1

REACTOR VESSEL MATERIALS

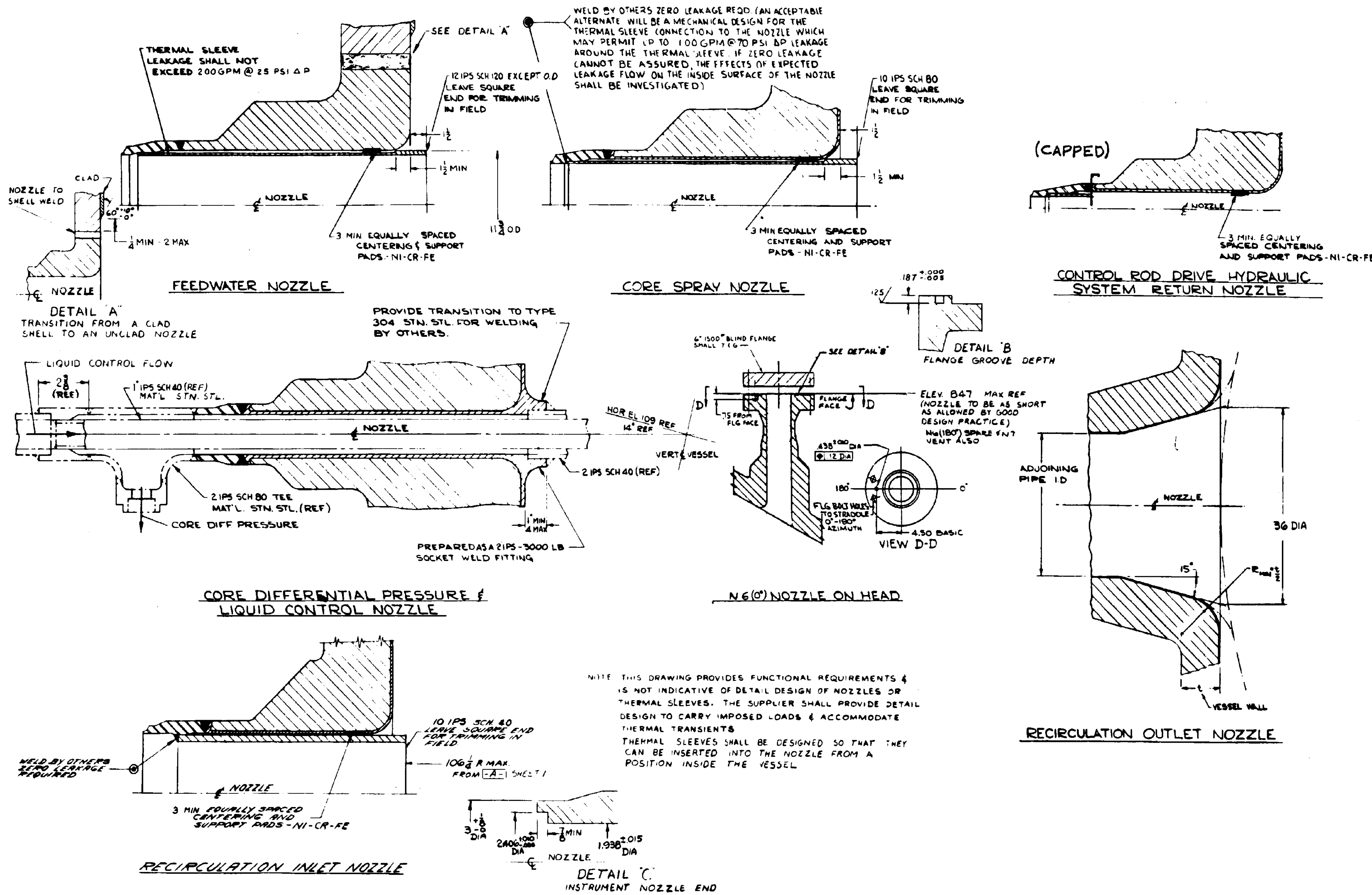
Component	Form	Material	Specification (ASME)
Heads and shell	Rolled plate	Low-alloy steel	SA533 Grade B[(a)]
Closure flange	Forged rings	Low-alloy steel	SA508 Class 2
Nozzles	Forged shapes	Low-alloy steel	SA508 Class 2
CRD stub tubes	Forged or extruded tubes	Clad low-alloy steel or inconel	SA508, SB166, or SB167
CRD housings	Pipe	Austenitic stainless steel	--
Incore housings	Pipe	Austenitic stainless steel	--
Cladding	Weld overlay	Austenitic stainless steel	--

a. ASME SA533 Grade B is the same specification as ASTM A533 C1.1.

TABLE 4.2-2

TYPICAL REACTOR VESSEL DATA

Reactor Vessel	
Inside diameter (in.) (minimum)	218
Inside length (ft)	69.3
Design pressure and temperature (psig/°F)	1250/575
Vessel Nozzles (no. and size) (in.)	
Recirculation outlet	2 - 28
Steam outlet	4 - 24
Recirculation inlet	10 - 12
Feedwater inlet	4 - 12
Core spray inlet	2 - 10
Head spray (blind flange)	1 - 6
CRD	137 - 6
Jet pump instrumentation	2 - 4
Vent	1 - 4
Instrumentation	6 - 2
CRD hydraulic system return	1 - 3
Core differential pressure and liquid control	1 - 2
Drain	1 - 2
Incore flux instrumentation	43 - 2
Head-seal leak detection	2 - 1
Estimated Weights (lb)	
Bottom head	122,000
Vessel cylinder	822,000
Vessel flange	41,000
Support skirt	20,000
Internals support	15,000
Nozzles	17,000
CRD housings	68,000
Stub tubes	6,000
Incore flux monitor housings	3,000
Total vessel without top head	1,114,000
Top head	135,000
Total vessel	1,249,000



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REACTOR VESSEL NOZZLES AND PENETRATIONS

FIGURE 4.2-1

4.3 REACTOR RECIRCULATION SYSTEM

4.3.1 POWER GENERATION OBJECTIVE

The objective of the reactor recirculation system (RRS) is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level. The current safety analysis report[3] and reactor operating pressure increase (ROPI) project report[4] demonstrate that the HNP-1 RRS can safely operate at a power level of 2804 MWt and 1060 psia.

4.3.2 POWER GENERATION DESIGN BASES

A. The RRS provides sufficient flow to remove heat from the fuel over the entire load range.

B. The RRS is designed to minimize maintenance situations that would require core disassembly and fuel removal.

4.3.3 SAFETY DESIGN BASES

A. The RRS is so designed that adequate fuel barrier thermal margin is assured following recirculation pump system malfunctions.

B. The RRS is so designed that a failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

C. The RRS is designed to maintain pressure integrity during adverse combinations of loadings and forces resulting from operation during anticipated operational occurrence (AOOs), accident, or special event conditions.

4.3.4 DESCRIPTION

The RRS consists of two recirculation loops external to the reactor vessel which provide the piping path for the driving flow of water to the reactor vessel jet pumps (figure 4.3-1 and drawing no. H-16066). Each external loop contains one variable-speed, motor-driven recirculation pump and two motor-operated gate valves. Each pump discharge line contains a venturi-type flow element. The recirculation loops are a part of the nuclear system process barrier and are located inside the primary containment structure. Table 4.3-1 summarizes the characteristics of the RRS.

An analysis of the RRS was done to determine the potential for damage due to water hammer. Since the RRS is filled with water, and is self-venting by configuration, the problem area of most concern is the potential for damage due to pressure waves caused by rapid changes in flow velocity.

The RRS valve closure time of 30 s (paragraph 7.4.3.5.4) is much too slow to cause water hammer. If instantaneous seizure of the recirculation pump should occur, stoppage of the impeller does not result in a large instantaneous change in flow velocity as would be required for water hammer effects to occur. This is because a large open flow area still exists through the pump impeller when it is stopped.

When the pump seizes, it changes from a device which aids the flow of water to a device which impedes its flow. Two pressure waves are sent out from the pump, which modify the flow. The wave that travels up the suction pipe is a compression wave, while the wave traveling down the discharge pipe is a rarefaction wave. Evaluation of the pressure waves, using equations of the form $\Delta P = C\Delta V$, results in a wave strength of < 200 psi. That is, the pressure in the suction pipe is < 200 psi above normal operating pressure, while the pressure in the discharge pipe is < 200 psi below normal operating pressure. This change in pressure is within the design capability of the piping system.

Since there is no further energy input to the system after the pump seizes, any conceivable combination of pressure wave reinforcement in the piping system caused by reflections from valves, elbows, orifices, etc., cannot exceed the strength of the original wave from which they were subdivided.

It is, therefore, concluded that water hammer effects in the RRS are negligible.

The recirculated coolant consists of saturated water from the steam separators and dryers which has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant exits from the vessel and passes through the two external recirculation loops to become the driving flow for the jet pumps. Each of the two external recirculation loops discharges high-pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pumps at the suction inlet and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section (figure 4.3-2). The adequacy of the total flow to the core is discussed in HNP-2-FSAR section 4.4, Thermal and Hydraulic Design. Tests have been conducted and documented[(1)] to show that the jet pump design is sound and that jet pump operation is stable and predictable.

When the pump is placed in service, it is started at slow speed with the main discharge valve closed and the nuclear system at full pressure. Pump speed is not increased until after the main valve has been opened. There is actually a very low probability that a recirculation loop that has been allowed to cool would need to be placed in service again with the nuclear system hot. The only valid reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the recirculation loop between the valves, i.e., excessive leakage through the pump mechanical seal. A leak of this nature cannot be repaired without shutting the plant down to permit access to the drywell; the nuclear system would in all probability have been cooled prior to repairing the leak.

Since the removal of RRS valve internals requires unloading of the nuclear fuel, the valves are provided with high quality back seats to permit stem packing renewal with the system full of water and to provide adequate leak tightness. The design objective of the back seats and trim is to minimize the need for maintenance of the valve internals.

Allowable heatup rate is 165°F/h for the recirculation pump piping and associated equipment. It is possible to keep the idle loop hot during one pump operation by leaving the nonoperating loop valves open, permitting the pressure head created by reverse flow through the idle jet pumps to cause reverse flow through the idle loop.

The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps, thus providing the additional net positive suction head (NPSH) available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is below 20%, the recirculation pump speed is automatically limited. Therefore, automatic protection against recirculation pump cavitation is provided by the 20% feedwater flow limiter. The reactor is designed so that it may be operated with only one recirculation pump.

The recirculation pumps can be operated to heat up the nuclear system for hydrostatic tests. At this time, they act in conjunction with any contribution from reactor core decay heat to raise nuclear system temperature above the limit imposed on the reactor vessel by nil ductility transition temperature considerations so that the hydrostatic test can be conducted.

Decontamination connections are provided in the piping on the suction and discharge side of the pumps (drawing no. H-16066) to permit flushing and decontamination of the pump and adjacent piping. These connections are arranged to permit the convenient and rapid connection of temporary piping. The piping low point drain is used during flushing or decontamination to remove crud from the piping low point; it is also designed for the connection of temporary piping.

Each recirculation pump is a single stage, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 to 57.5 Hz. For loop startup, each pump operates at a speed corresponding to a power supply frequency of 11.5 Hz with the main discharge gate valve closed.

The recirculation pump shaft seal assembly consists of two seals built into a cartridge which can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or operating. Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal should fail. A breakdown bushing in the pump casing reduces leakage in the event of a gross failure of both shaft seals. The pressure drop across each individual seal can be monitored, as well as the cavity temperature of each seal. The seal leakage is piped to a flow-measuring device which alarms on high leakage.

Each recirculation pump motor has a variable speed, ac electric motor which can drive the pump over a controlled range of 20 to 100% of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 Hz.

Electrical equipment is designed, constructed, and tested in accordance with applicable sections of the National Electrical Manufacturers Association standards.

A variable frequency, adjustable speed drive (ASD) located outside the drywell supplies power to each recirculation pump motor. The pump motor is electrically connected to the ASD and is started by changing the frequency and voltage of the supply to the motor. Minimum speed corresponds to a frequency of 11.5 Hz.

The rotating inertia of the recirculation pump and motor provides an acceptable coastdown of flow following loss of power to the driven motors, so that the core is adequately cooled during AOOs.

Erosion, corrosion, and material fatigue were accounted for in the design of the pump casings. Aging management programs (HNP-2-FSAR subsections 18.2.1, 18.2.12, 18.3.2, and 18.5.1) monitor the condition of the pump so that actions are taken to provide reasonable assurance that the components are capable of performing their intended functions for 40 years and beyond. The pump drive motor, impeller, and wear rings are designed for as long a life as is practical. The design objective is to provide a unit which does not require removal from the system for rework or overhaul more often than once every 5 years.

The RRS is designed and constructed to meet the requirements described in appendix A. The suction and discharge lines are welded to the pump casing.

Except for the ASD, the RRS is designed as Class 1 seismic equipment. As such, it is designed to resist sufficiently the response motion at the installed location within the supporting structure for the design basis earthquake, assuming the pump is filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The recirculation piping, valves, and pumps are supported by constant support hangers and by sway braces to avoid the use of piping expansion loops, which would be required if the pumps were anchored. In addition, to limit pipe motion the recirculation loops are provided with a system of restraints so designed that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. Impact loading is not considered on limit stops, since possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement.

The RRS piping, valves, and pump casings are covered with thermal insulation. The type of insulation is either all-metal, reflective or conventional, asbestos; it is prefabricated into components for field installation. Removable insulation is provided at various locations to permit periodic inspection of the equipment.

4.3.5 SAFETY EVALUATION

The RRS malfunctions that pose threats of damage to the fuel barrier are described and evaluated in HNP-2-FSAR chapter 15, Safety Analysis. There it is shown that none of the malfunctions results in fuel damage; thus, the RRS has sufficient flow coast down characteristics to maintain fuel thermal margins during AOOs.

Figure 4.3-3 shows the core flooding capability provided by a jet pump design plant. No recirculation line break can prevent reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of a jet pump design plant is discussed in detail in the emergency core cooling system document[2] filed with the Atomic Energy Commission as a General Electric topical report.

Piping and pump design pressures for the RRS are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop and appropriate pump head allowance. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria provides assurance that a system designed, built, and operated within design limits has an extremely low probability of failure due to any known failure mechanism.

4.3.6 INSPECTION AND TESTING

Quality control methods were used during fabrication and assembly of the RRS to assure that design specifications were met. Inspection and testing were carried out as described in appendix A.

The reactor coolant system was thoroughly cleaned and flushed before fuel was loaded initially.

During the preoperational test program, the RRS was hydrostatically tested at 125% reactor vessel design pressure. Preoperational tests on the RRS also included checking for proper operation of the valves. Pumps and MG sets were preoperationally tested, and operation of the flow control system was checked. MG sets have later been replaced by ASDs.

During the startup test program horizontal and vertical motions of the RRS piping and equipment were observed and supports were adjusted, as necessary, to assure that components were free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressure were evaluated during the startup tests. Plant power response to recirculation flow control was determined.

A vibration operational test was conducted at HNP-1 on the RRS. Vibration was measured during normal operation of the RRS to determine the effects of pump rotation and flow. Deflections of the RRS had been calculated, which would produce alternating stresses in the system < 10,000 psi. Measurements were made to ensure actual deflections were less than the allowable deflections.

Routine vibration measurements are not made for any of the transient conditions. Vibration could be created in the recirculation piping system by either valve closure or pump seizure. Vibration could occur in the main steam piping from either turbine stop valve closure or relief valve opening.

To assure adequate working space and access for inspection of selected components, inservice inspection was considered in the design of the RRS. Design provisions for access met the intent of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, "Inservice Inspection of Nuclear Reactor Coolant Systems," dated January 1, 1970. See appendix H for current inservice inspection requirements.

REFERENCES

1. "Design and Performance of General Electric Boiling Water Reactor Jet Pumps," APED-5460, General Electric Company, Atomic Power Equipment Department, September 1968.

2. Ianni, P. W., "Core Standby Cooling Systems for Boiling Water Reactors," APED-5458, General Electric Company, Atomic Power Equipment Department, March 1968.

3. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

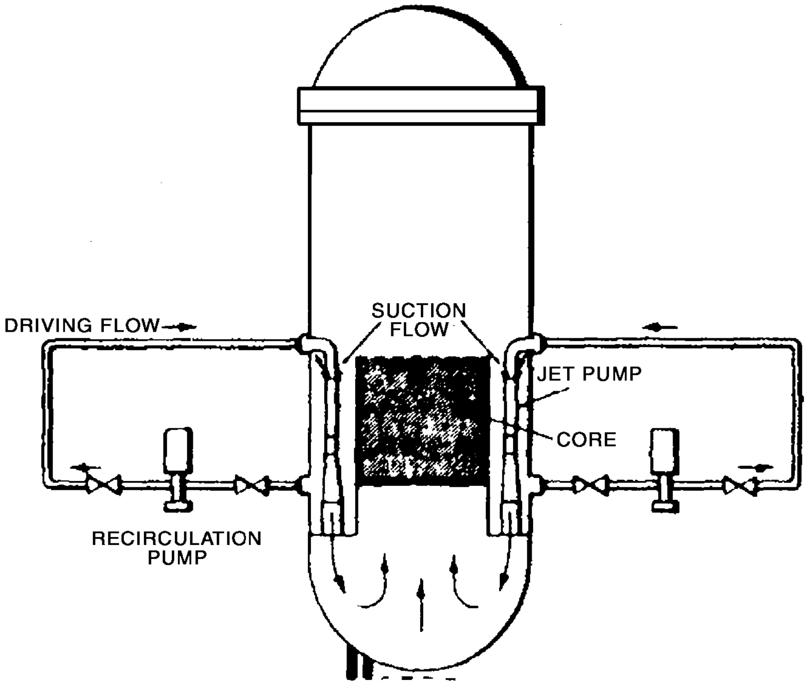
4. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 4.3-1

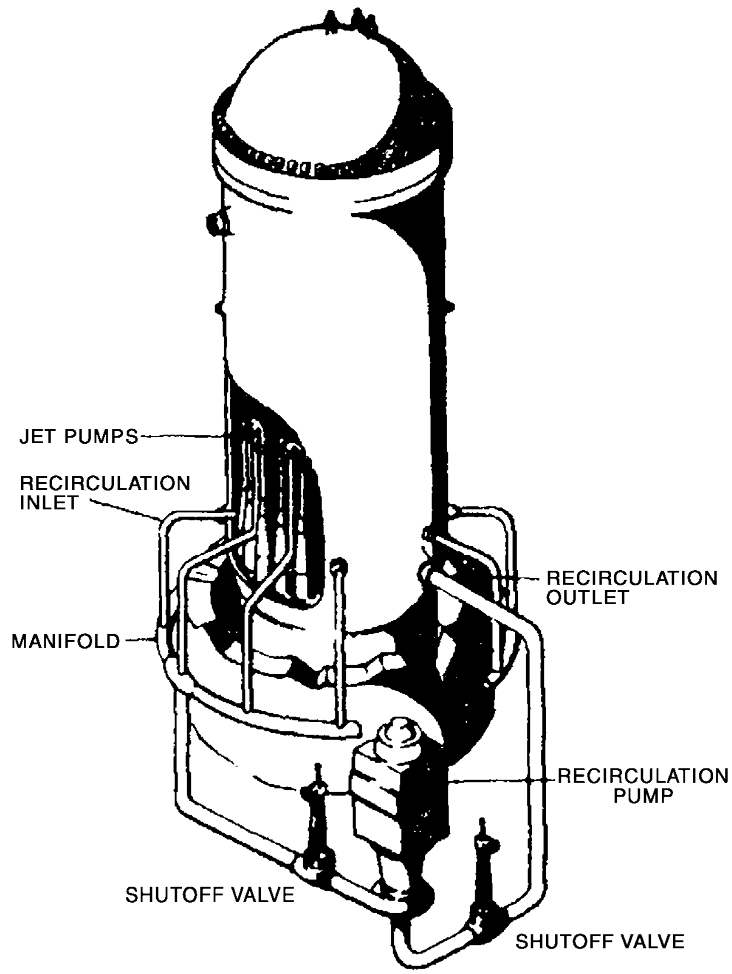
REACTOR RECIRCULATION SYSTEM DESIGN DATA

External Loops		
Number of loops	2	
Pipe sizes (nominal outside diameter)		
Pump suction	28 in.	
Pump discharge	28 in.	
Discharge manifold	22 in.	
Recirculation inlet line	12.75 in.	
Design pressure/design temperature		
Suction piping	1150/562	psig/°F
Discharge piping	1325/562	psig/°F
Operation at Rated Conditions		
Recirculation pump (each)		
Flow	~ 45,200	gal/min
Flow	17.1×10^6	lb/h
Total developed head	530	ft
Suction pressure (static)	1055	psia
Available NPSH (minimum)	460	ft
Water temperature (maximum)	533	°F
Pump	5260	hp brake
Flow velocity at pump suction	~ 28.3	ft/s
Drive motor and power supply		
Frequency (at rated)	56	Hz
Frequency (operating range)	11.5 - 57.5	Hz
ASD maximum input power rating	6665*	kVA
Jet pumps		
Number	20	
Total jet pump diffuser flow	78.5×10^6	lb/h
Throat inside diameter (ID)	6.86	in.
Diffuser ID	17.0	in.
Nozzle ID	3.40	in.(nominal)
Diffuser exit velocity	14.7	ft/s
Jet pump head	80.4	ft

*Actual power requirement is load dependent and is less than the kVA rating.



ELEVATION



ISOMETRIC

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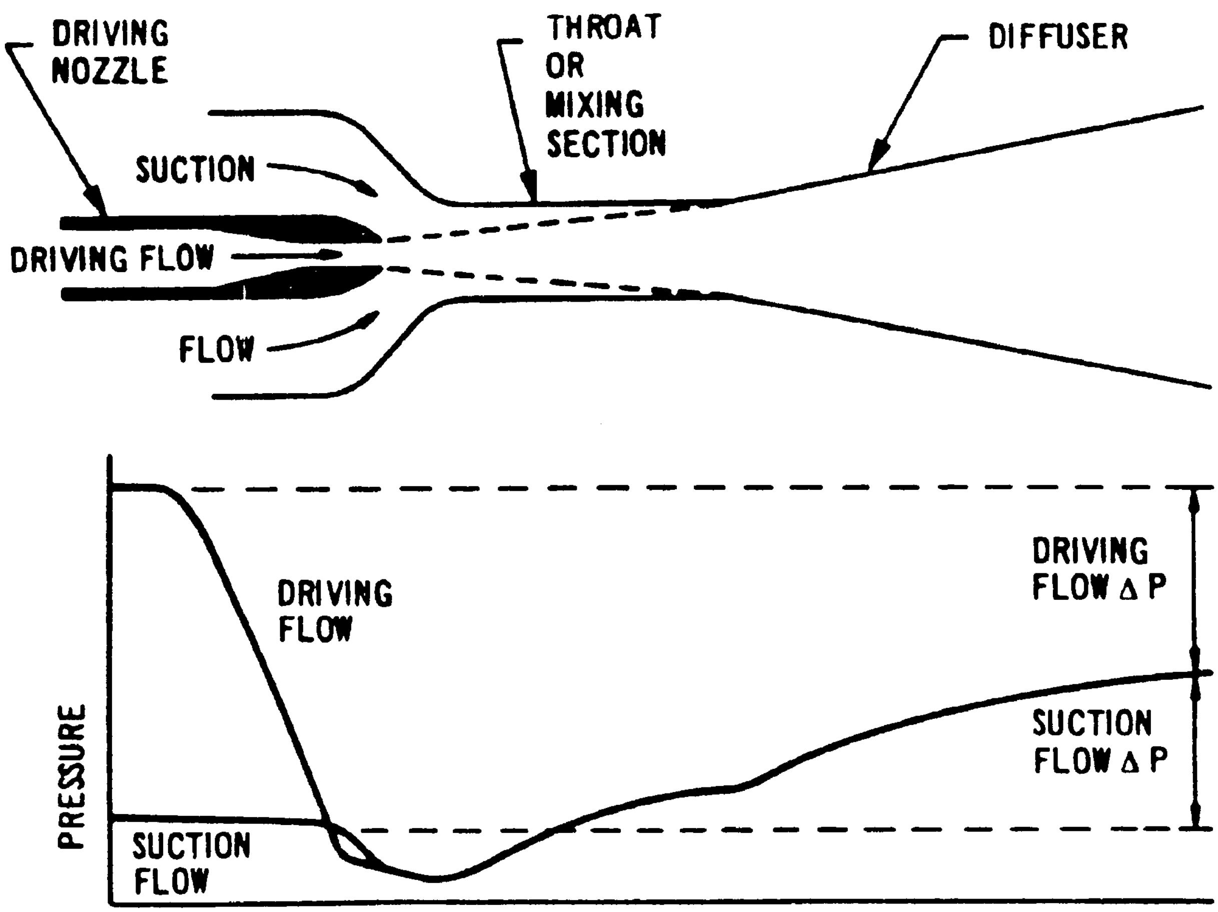
REACTOR RECIRCULATION SYSTEM
ELEVATION AND ISOMETRIC

FIGURE 4.3-1



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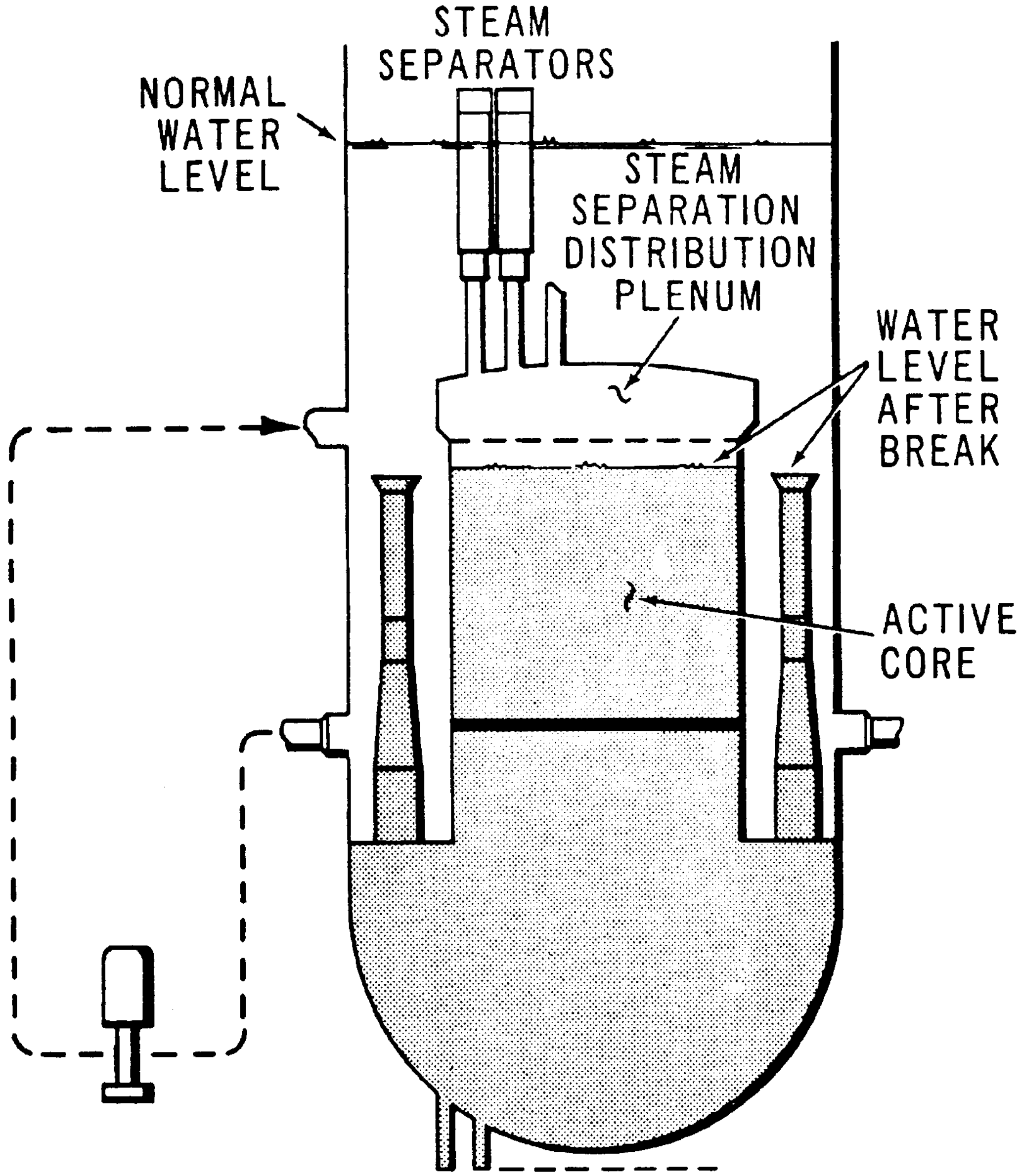
JET PUMP – – OPERATING PRINCIPLE

FIGURE 4.3-2



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REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

RECIRCULATION SYSTEM-CORE FLOODING CAPACITY

FIGURE 4.3-3

4.4 PRESSURE RELIEF SYSTEM

4.4.1 POWER GENERATION OBJECTIVE

The power generation objective of the pressure relief system is to limit any overpressure which occurs during anticipated operational occurrences (AOOs). The current safety analysis report[(3)] and reactor operating pressure increase (ROPI) project report[(4)] demonstrate that the HNP-1 pressure relief system can safely operate at a power level of 2804 MWt and 1060 psia.

4.4.2 POWER GENERATION DESIGN BASES

A. The safety relief valves (SRVs) limit vessel pressure during normal plant isolations and load rejections.

B. The SRVs discharge to the primary containment suppression pool.

C. The SRVs properly reclose following a plant isolation or load rejection so that normal operation can be resumed as soon as possible.

4.4.3 SAFETY OBJECTIVE

The safety objective of the pressure relief system is to prevent overpressurization of the nuclear system; this protects the nuclear system process barrier from failure which could result in the uncontrolled release of fission products. In addition, the automatic depressurization feature of the pressure relief system acts in conjunction with the emergency core cooling system (ECCS) for reflooding the core following small breaks in the nuclear system process barrier; this protects the reactor fuel barrier (UO_2 sealed in cladding) from failure due to overheating.

4.4.4 SAFETY DESIGN BASES

A. The pressure relief system prevents overpressurization of the nuclear system in order to prevent failure of the nuclear system process barrier due to pressure.

B. The pressure relief system provides automatic depressurization for small breaks in the nuclear system so that low-pressure coolant injection and the core spray system can operate to protect the fuel barrier.

C. The relief valve discharge piping is designed to accommodate forces resulting from relief action and supported for reactions due to flow at maximum relief discharge capacity so that system integrity is maintained.

D. The pressure relief system is designed for testing prior to nuclear system operation and for verification of the operability of the pressure relief system.

E. The pressure relief system is designed to withstand adverse combinations of loadings and forces resulting from operation during AOO, accident, or special event conditions.

4.4.5 DESCRIPTION

The pressure relief system includes 11 SRVs, all of which are located on the main steam lines within the drywell between the reactor vessel and the first isolation valve. (See figures 4.4-1 and 4.4-2.) The SRVs provide protection against overpressure of the nuclear system and discharge directly to the suppression pool. Table 4.4-1 shows the set pressures and capacities of the valves.

The main steam lines on which the SRVs are mounted are designed, installed, and tested in accordance with the applicable code discussed in appendix A. The SRVs are distributed among the four main steam lines so that a single accident cannot completely disable a safety relief or automatic depressurization function. (See figures 4.4-1 and 4.4-2 for location of the valves and piping.) Two pressure switches are located on the tailpipe (discharge line) of each SRV. Each switch is powered from a separate Class 1E power source. Calibration verification of setpoint and testing of these pressure switches is performed at regular intervals as stated in the Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1) Technical Specifications.

The SRVs are designed, constructed, and marked with data in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Article 9. Popping-point tolerance (pressure at which the valve pops wide open) is ± 3% of the set pressure. Each valve is self-actuating at the set relieving pressure. Automatic depressurization system (ADS) valves are provided with power-actuated devices capable of opening the valve at any steam pressure above 100 psig and capable of holding the valve open until the steam pressure decreases to about 50 psig. The control system for the actuator is described in section 7.4, Emergency Core Cooling System Control and Instrumentation. A nonsafety electrical backup to the mechanical relief is wired to open the SRVs just at setpoints distributed among 3 groups (table 4.4-1).

Pressure-containing parts of the main valve body are fabricated of ASME SA-105, Grade II. The pressure-containing parts of the valve top works are fabricated of ASME SB-564, Inconel 600. The relief valves are designed for operation with saturated steam. The relieving pressures for overpressure relief and safety operating modes are adjustable between 1100 to 1200 psig with a maximum back pressure of 40% of the set pressure. The delay time (maximum elapsed time between overpressure signal and actual valve motion) is $<$ 0.4 s, and the response time (main disc stroke time) is $<$ 0.1 s. The three-stage, pilot-operated safety relief valve consists of two principle assemblies: a two-stage pilot valve section (top works) and the main valve section. (See figure 4.4-3.) The pilot valve section is the pressure sensing and control element, and the main valve is a hydraulically (system fluid) actuated follower valve which provides the pressure relief function. The pilot valve section consists of two stages: a small pilot stage control valve and a larger second stage valve which actuates the main stage valve. The key element of the pilot valve is the machined bellows which acts as a combination piston, spring and hermetic seal. The top of the bellows is connected to the pilot stage disc through a stem and disc yoke, between which there is an adjustable clearance or “abutment gap.” The main stage consists essentially of a large piston which includes the main valve disc, the main valve chamber, and a preload spring. The remote air actuator section strokes the second stage disc which causes the main valve to open. It is actuated by air pressure supplied externally and applied to a diaphragm. A typical sequence of operation for overpressure relief self-actuation can be described as follows:

A. When the reactor is at operating pressure below the setpoint of the valve, the top works and main stage chamber are at system pressure with the valve in the closed position. (See figure 4.4-3.) The bellows preload force seats the pilot stage disc tightly and prevents reverse leakage at low system pressures or high back pressures. The main valve disc is tightly seated by the combined forces exerted by the main valve preload spring and the system internal pressure, which acts over the area of the main valve disc. In the closed position, the static pressures are equal in the valve body and in the chamber over the main valve piston. This pressure equalization is made possible by leakage past the piston, via the ring gap, piston orifice and drain and vent grooves.

B. As the system pressure increases the bellows preload force is reduced to zero. From this point, the pilot stage disc is held closed by the internal pressure acting over the pilot stage seat area. This hydraulic seating force increases with increasing system pressure and prevents leakage or “simmering” at pressures near the valve set pressure.

C. As a system pressure increases further, bellows expansion reduces the abutment gap between the stem and disc yoke. When the stem abuts against the yoke, further pressure increase reduces the net pilot seating force to zero and lifts the disc from its seat.

D. Once the pilot stage starts to open, the hydraulic seating is reduced, resulting in a net increase in the force tending to extend the bellows. Opening of the pilot stage admits fluid to the operating piston of the second stage, causing it to open.

E. With the pilot and second stage of the pilot valve assembly full open the main piston chamber is vented to the discharge piping. This venting action creates a differential pressure across the main valve piston in a direction tending to open the valve. The main valve piston is sized such that the resultant opening force is greater than the combined spring load and hydraulic seating force. The bellows is designed to control the valve blowdown by holding the pilot stage disc open until the proper reclosing pressure is reached. The bellows is connected by a passage to the inlet side of the valve.

F. As occurs in the case of the pilot stage, once the main valve disc starts to open, the hydraulic seating force is reduced; this causes a significant increase in opening force and the characteristic full opening or popping action.

G. When the pressure has been reduced sufficiently to permit the pilot stage to close, the second stage reseats after depressurization of the second stage piston chamber accomplished by leakage past the piston rings and piston orifice.

Leakage of system fluid past the main valve piston repressurizes the chamber over the piston, eliminates the hydraulic opening force, and permits the preload spring and flow forces to close the valve. Once the valve is closed, the additional hydraulic seating force due to system pressure acting on the main valve disc seats the main valve tightly and prevents leakage.

The relief valves are installed so that each valve discharge is piped through its own discharge line to a point below the minimum water level in the primary containment suppression pool, permitting the steam to condense in the pool. The relief valve discharge lines extend to the deepest part of the suppression pool where they have a minimum submergence of 8 ft. Each line terminates in a tee which eliminates unbalanced thrust forces on the pipe and its supports and anchors. The tees are located 4 ft 6 in. from the bottom of the torus and are oriented such that the discharged water and steam do not directly impinge on the torus shell or other structures. Water in the line above suppression pool water level would cause excessive pressure at the relief valve discharge when the valve is again opened. For this reason, vacuum relief valves are provided on each relief valve discharge line to prevent drawing water up into the line due to steam condensation following termination of relief valve operation. The relief valves are located on the main steam line piping rather than on the reactor vessel top head primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, the safety relief valves are more accessible during a shutdown to correct possible valve malfunctions when they are located on the steam lines.

The mechanical actuation mode is augmented by an electrical actuation logic used as a backup. Each SRV can be actuated by its electric pilot solenoid valve. Each of the four steam lines is monitored by a pressure transmitter tied to three trip units (drawing nos. H-16062 and H-16063). The setpoints for the electrical backup are distributed among 3 groups (table 4.4-1). Each of the three trip units is set to one of these group settings. The trip units reset at a pressure below the mechanical closing pressure (drawing no. H-19909). This redundant control capability is, in itself, nonsafety-related and is isolated by fuses from the safety-related portion of the pilot valve's circuit that serves either the ADS or the low-low set (LLS) system. The equipment serving the backup functions is nonsafety-related (reference 1).

Criteria for the design and installation of safety relief valves include the following:

- A conservative clearance of 6 in. between each SRV and nearby structures, systems, and components (SSC) was established during plant design. This clearance prevents interference and potential damage to the SRVs and other SSCs during dynamic events such as SRV valve discharge. Where the 6-in. clearance has been encroached upon in the past, specific analyses based on the expected movements of equipment under dynamic loading conditions have determined that sufficient clearance exists to prevent damage to the SRVs and nearby SSCs. Installation of future SSCs should maintain the 6-in. clearance unless similar specific analysis is performed as part of the design change or installation process.

- Adequate space is provided between welds of sweepolet on header for valve inspection.

- Clearance is provided between header and bottom of flange for both installation and removal of the valve.

- Flatness tolerances and machined groove surfaces are specified for safety relief valve flanges.

- A larger flange rating of 1500 lb was provided for structural stability instead of a pressure rating of 900 lb for pressure/temperature rating.

- A larger pipe schedule is provided for structural stability than required by pressure and temperature considerations.

- Equalization of the discharge thrust forces is provided for safety relief valves by the routing of the discharge thrust forces through piping to the suppression pool.

To account for the full discharge thrust loads in the design of the safety relief valves, the following special loadings are considered in addition to the usual design loads, i.e., weight, pressure, temperature, and earthquake:

- The jet force exerted on the relief and safety valves during the first millisecond when the valve is open and before steady-state flow has been established. (With steady-state flow, the dynamic flow reaction forces are self-equilibrated by the safety relief valve discharge piping.)

- The dynamic effects of the kinetic energy of the piston disc assembly when it impacts on the base casting of the valve.

All code allowable stresses are met with these special loads acting concurrently with other design loads. The highest stress occurs at the branch connection below the valve.

The condition of common mode failure for the dual function safety relief valves for a rapid loss of main condenser vacuum is discussed in detail in APED Topical Report NEDO-10189, "An Analysis of Functional Common Mode Failures in General Electric Boiling Water Reactor Protection and Control Instrumentation," dated July 1970. In particular, subsection 4.1.5 presents an analysis of this condition, and figure 4.5.J depicts the results of the analysis.

Each relief valve is equipped with an air accumulator and check valve arrangement. These accumulators provide assurance that the valves can be held open following failure of the air supply to the accumulators, and they are sized to contain sufficient air for a minimum of five valve operations with containment at atmospheric pressure. Further descriptions of the operation of the automatic depressurization system and the LLS relief logic system are found in chapter 6 and in section 4.11, respectively.

Depressurization of the nuclear system can be effected manually in the event the main condenser is not available as a heat sink after reactor shutdown. The steam generated by core decay heat is discharged to the suppression pool. To control nuclear system pressure, the relief valves are operated by remote-manual controls from the main control room. The number, set pressure, and capacities of relief valves are given in table 4.4-1.

4.4.6 SAFETY EVALUATION

The ASME Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III requirements be protected from overpressure. The code permits a peak allowable pressure of 110% of vessel design pressure. The code specifications for safety valves require that:

- The lowest safety valve be set at or below vessel design pressure.

- The highest safety valve be set to open ≤ 105% of vessel design pressure.

The SRVs are set to open by self-actuation (overpressure safety mode, table 4.4-1). This satisfies the ASME Code specifications for safety valves, since the lowest set valve opens at < 1250 psig (nuclear system design pressure) and the highest set valve opens < 1312.5 psig (105% of nuclear system design pressure). A nonsafety electrical backup to the mechanical relief is wired to open at setpoints distributed among 3 groups (table 4.4-1).

The sizing of the SRV capacity is discussed in HNP-2-FSAR, supplement 5A.

The SRV performance requirements were updated in references 2, 3, and 4. The analysis indicated that a design relief valve capacity of 71% rated flow is capable of maintaining adequate margin below ASME Code allowable pressure in the nuclear system (1375 psig). The sequence of events assumed in this analysis was investigated only to meet code requirements and to evaluate the pressure relief system.

Closure of all MSIVs with a flux scram is the most limiting event associated with the overpressure protection requirements. (See HNP-2-FSAR paragraph 5.2.2.3.)

The automatic depressurization capability of the pressure relief system is evaluated in chapter 6 and in section 7.4.

The LLS function of the pressure relief system is discussed in section 4.11.

The relief valve discharge piping is designed, installed, and tested as outlined in appendix A.

4.4.7 INSPECTION AND TESTING

The SRVs are tested in accordance with the manufacturer's quality control procedures to detect defects and to prove operability prior to installation. The following final tests are witnessed on an audit basis by a representative of the purchaser:

- Hydrostatic test at ANSI specified conditions.

- Pneumatic seat leakage test at 93% of set pressure with maximum permitted leakage.

- Set pressure test: The valve is pressurized with saturated steam, or other appropriate test medium, with the pressure rising to the valve set pressure.

- Response time test: Each relief valve is tested to demonstrate acceptable response time.

The relief valves are installed as received from the factory. The setpoints are adjusted, verified, and indicated on the valves by the vendor. Proper manual and automatic actuation of the relief valves is verified during the preoperational test program.

It is recognized that it is not feasible to test the relief valve setpoints while the valves are in place or during normal plant operation. The valves are mounted on 6-in. diameter, 1500-lb primary service rating flanges so that they can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. The external surface and seating surface of all relief valves are 100% visually inspected when the valves are removed for maintenance or bench checks.

The SRV pressure switches are tested and calibrated in accordance with the HNP-1 Technical Specifications.

REFERENCES

1. Nuclear Regulatory Commission - Safety Evaluation (Main Steam Safety Relief Valve Pressure Sensor Activation Modification, Hatch Nuclear Plant), Docket Nos. 50-321 and 50-366, report dated July 24, 1992.

2. "Safety Review for Edwin I. Hatch Nuclear Power Plant Units 1 and 2 - Updated Safety/Relief Valve Performance Requirements," NEDC-32041P, General Electric Company, April 1996.

3. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

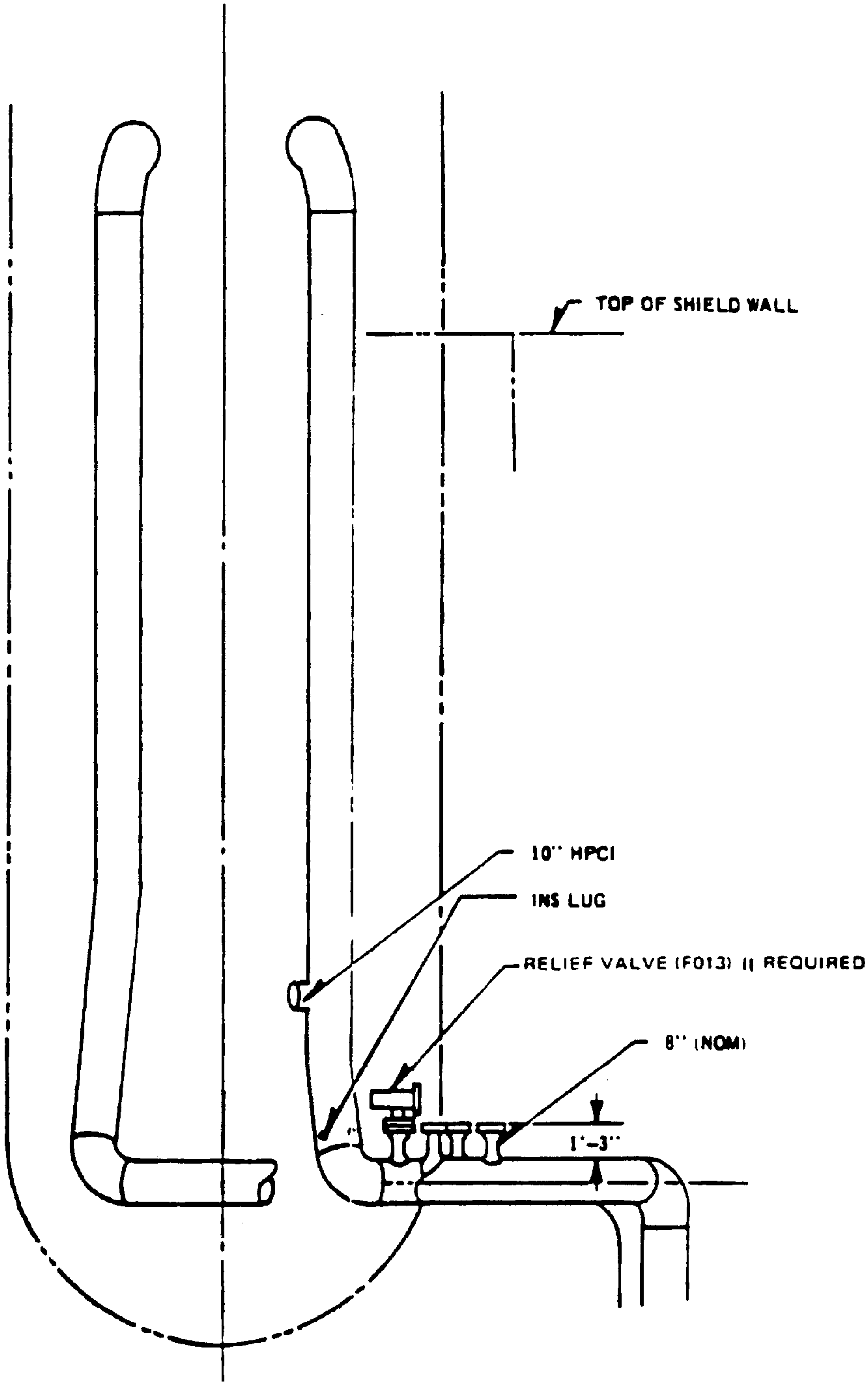
4. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 4.4-1

NUCLEAR SYSTEM SRVs AND ELECTRICAL BACKUP SET PRESSURES AND CAPACITIES

	No. of SRVs	Mechanical Set Pressure (psig)	Set Pressure (psig)[b]	Approximate Capacity at 103% of Mechanical Set Pressure (each) (lb/h)
	4	1150	1120	916,600
	4	1150	1130	916,600
	3	1150	1140	916,600
TOTAL	11(7)[a]			

a. The number in parentheses indicates the number of SRVs which serve in the automatic depressurization capacity.
b. This column reflects nominal SRVs set pressure for nonsafety electrical backup to mechanical relief valves.



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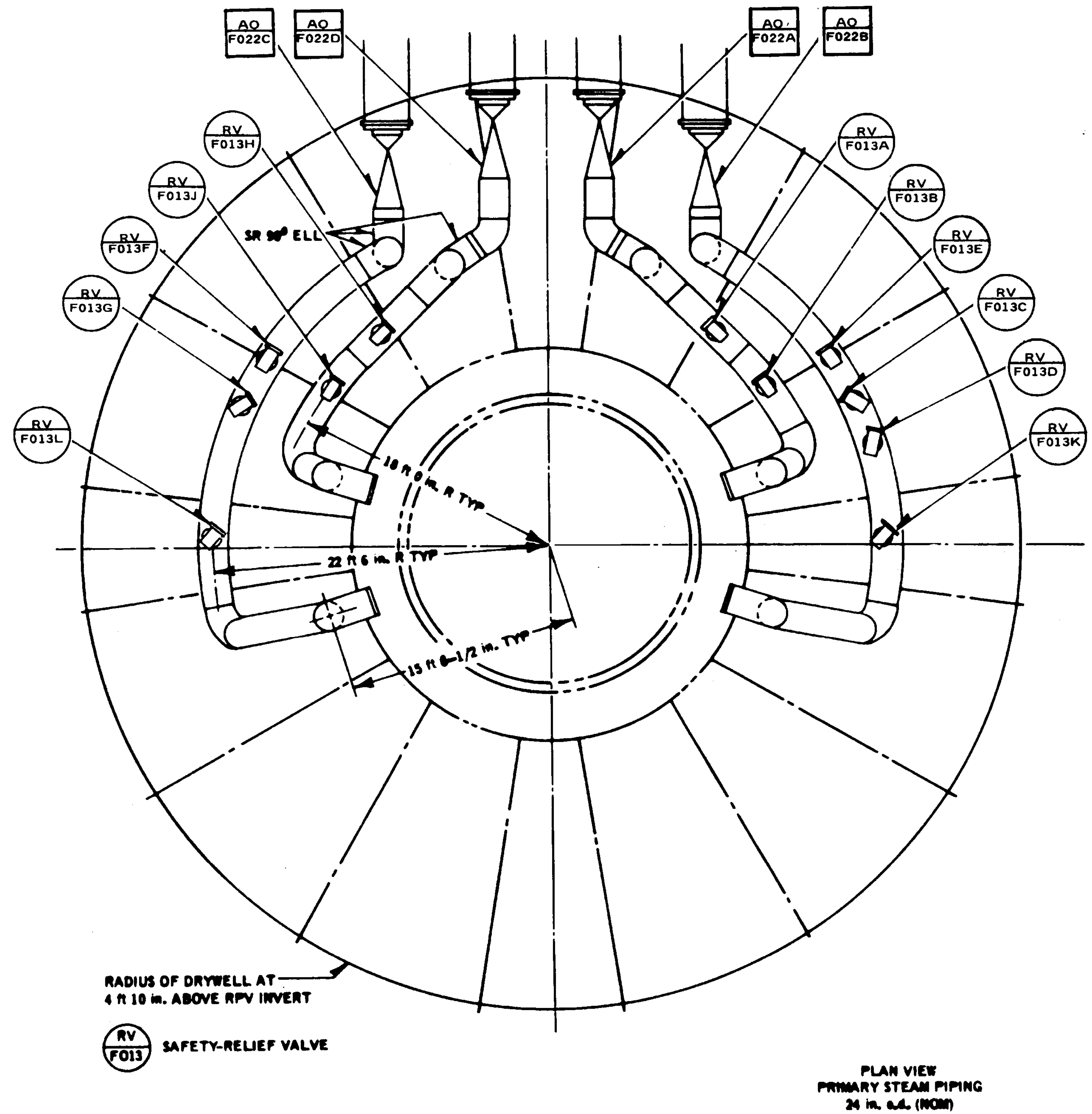
LOCATIONS OF SAFETY RELIEF VALVES – SIDE VIEW

FIGURE 4.4-1



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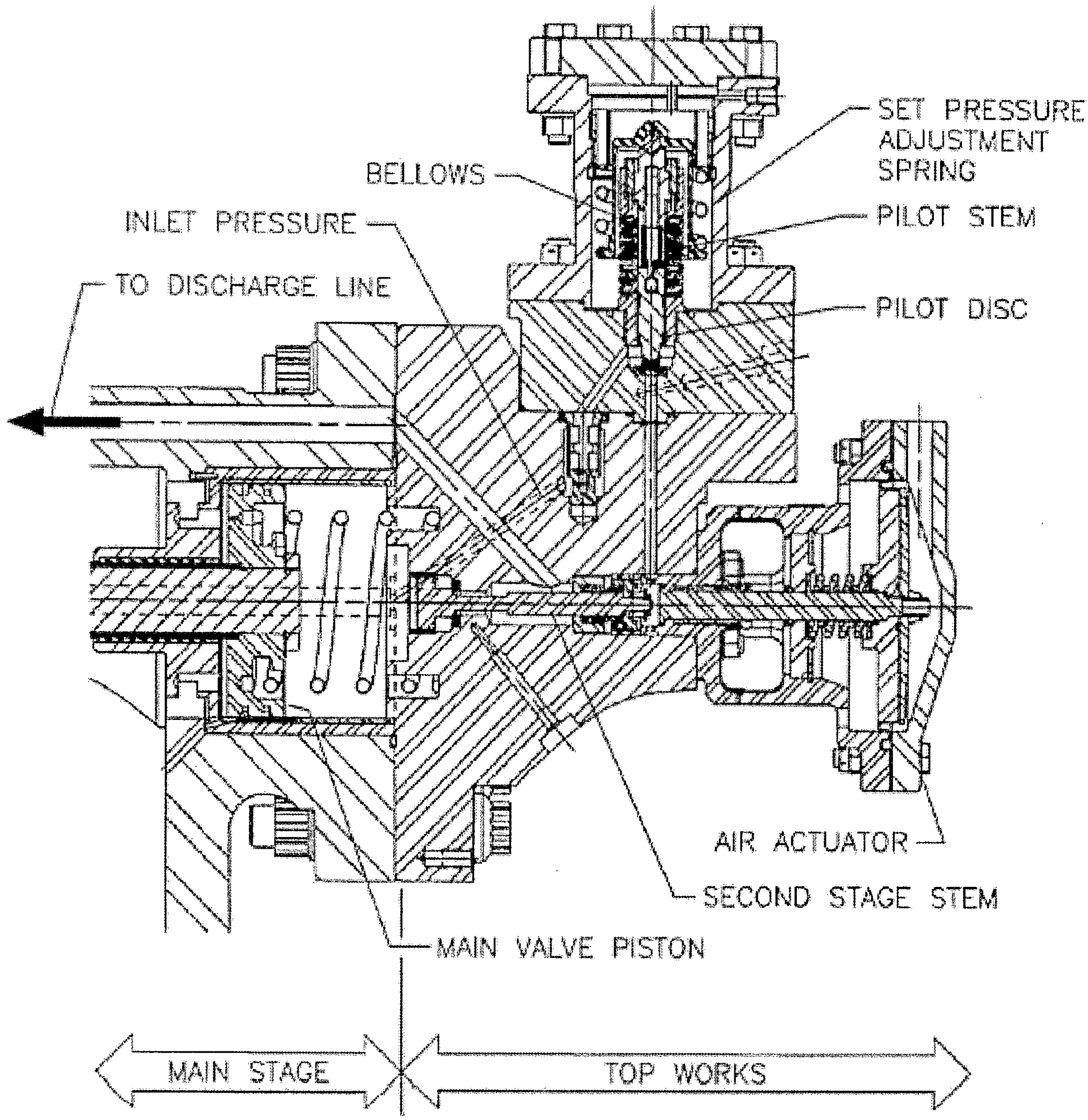
SOUTHERN COMPANY Energy to Serve Your World®	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	LOCATIONS OF SAFETY RELIEF VALVES – TOP VIEW FIGURE 4.4-2



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THREE-STAGE TOPWORKS

Figure 4.4-3

4.5 MAIN STEAM LINE FLOW RESTRICTOR

4.5.1 SAFETY OBJECTIVE

To protect the fuel barrier, the main steam line flow restrictors limit the loss of coolant from the reactor vessel before main steam isolation valve (MSIV) closure, and in case a main steam line should rupture outside the primary containment. The current safety analysis report[1] and reactor operating pressure increase (ROPI) project report[2] demonstrate that HNP-1 main steam line flow restrictors can safely operate at a power level of 2804 MWt and 1060 psia.

4.5.2 SAFETY DESIGN BASES

A. The main steam line flow restrictor is designed to limit the loss of coolant from the reactor vessel following a steam line rupture outside the primary containment to the extent that the reactor vessel water level does not fall below the top of the core within the time required to close the MSIVs.

B. The main steam line flow restrictor is designed to withstand the maximum pressure difference expected across the restrictor following complete severance of a main steam line.

4.5.3 DESCRIPTION

A main steam line flow restrictor (figure 4.5-1) is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line between the reactor vessel and the first MSIV and downstream of the main steam line safety and relief valves. The restrictor limits the coolant blowdown rate from the reactor vessel in the event a main steam line break occurs outside the primary containment to the maximum (choke) flow specified. The restrictor assembly consists of a venturi-type nozzle insert welded into the main steam line in accordance with applicable code requirements. The restrictor assembly is self-draining. (Low point pockets are drained internally to the main steam line.) The flow restrictor is designed and fabricated in accordance with the requirements listed in appendix A.

The flow restrictor has no moving parts, and the mechanical structure of the restrictor is capable of withstanding the velocities and forces under main steam line break conditions where maximum differential pressure is conservatively assumed to be equal to 1375 psi, the American Society of Mechanical Engineers (ASME) code limit.

The ratio of the venturi throat diameter to a steam line diameter is ~ 0.5139. This results in a pressure differential of 10-psi maximum at rated flow. This design limits the steam flow in a severed line to about 200% rated flow, yet it results in a negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

4.5.4 SAFETY EVALUATION

In the event a main steam line breaks outside the primary containment, the steam flowrate is restricted in the venturi throat by a two-phase mechanism which is similar to the critical flow phenomenon in gas dynamics. This restriction limits the steam flowrate, thereby reducing the reactor vessel coolant blowdown, and the increase in fuel cladding temperature subsequent to the blowdown. This reduces the probability of fuel failure and its consequences.

Analysis of the MSLBA (HNP-2-FSAR chapter 15, Safety Analysis, section 15.3) shows that the core remains covered with water, and the amount of radioactive material released to the environs through the MSLBA does not exceed the guideline values of published regulations.

Tests were conducted on a scale model to determine final design and performance characteristics of the flow restrictor, including the maximum flowrate of the restrictor corresponding to the accident conditions, the irreversible losses under normal plant operating conditions, and the discharge moisture level. The tests showed that the flow restrictor operation at critical throat velocities is stable and predictable. Unrecovered differential pressure across a scale model restrictor is consistently around 10% of the total nozzle pressure differentials, and the restrictor performance is in agreement with existing ASME correlation. Full-size restrictors have a hydraulic shape that is slightly different and a differential pressure loss of ~ 15%.

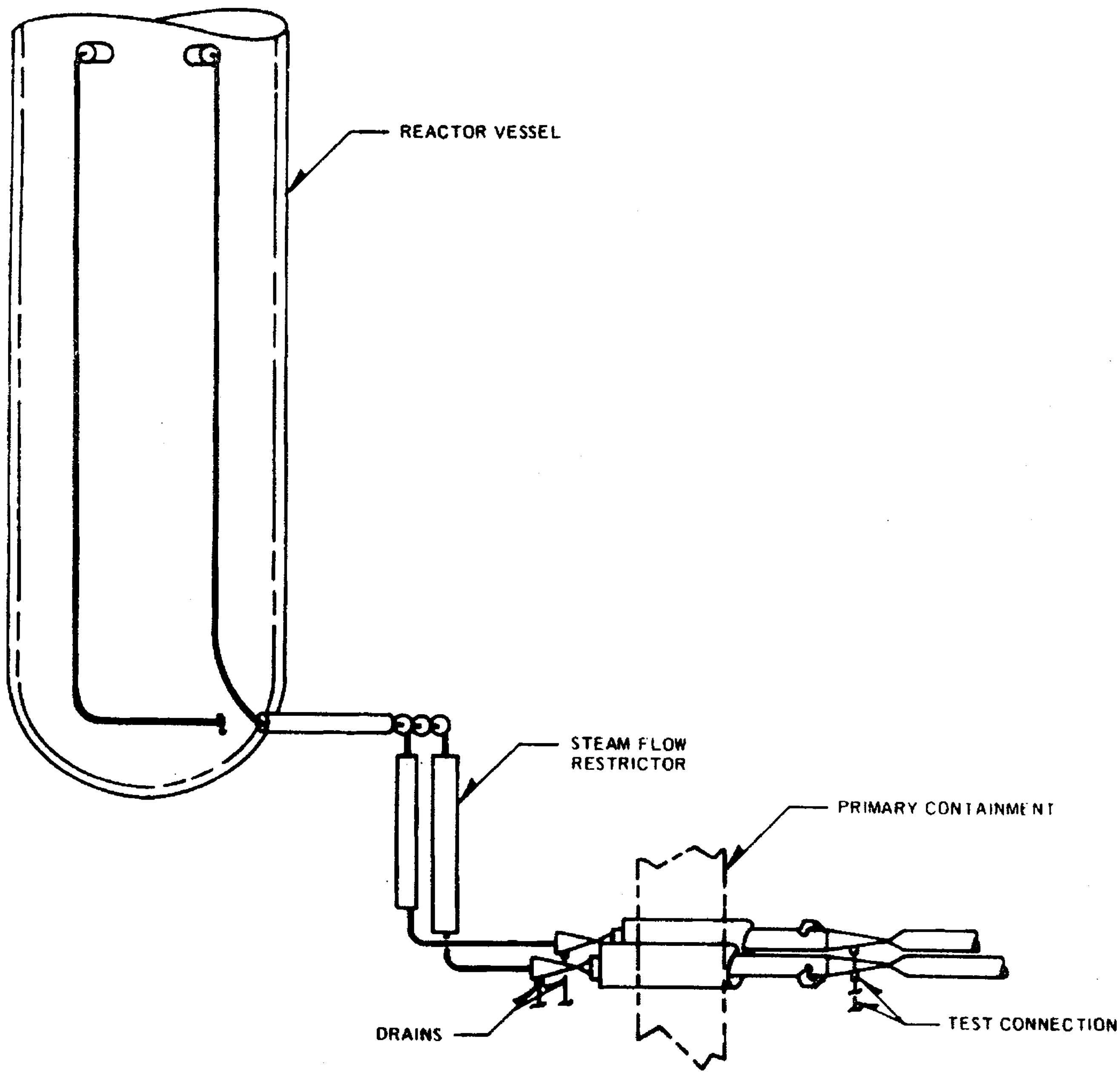
4.5.5 INSPECTION AND TESTING

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion will occur with time, and such a slight enlargement will have no safety significance.

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.



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MAIN STEAM LINE
FLOW RESTRICTOR LOCATION

FIGURE 4.5-1

4.6 MAIN STEAM ISOLATION VALVES

The current safety analysis report[1] and reactor operating pressure increase (ROPI) project report[2] demonstrate that HNP-1 main steam isolation valves can safely operate at a power level of 2804 MWt and 1060 psia.

4.6.1 SAFETY OBJECTIVES

Two isolation valves (one on each side of the primary containment barrier) in each of the main steam lines close automatically to:

- Prevent damage to the fuel barrier by limiting the loss of reactor cooling water in the case of a major leak from steam piping outside the primary containment.
- Limit release of radioactive material to the plant environs by closing the nuclear system process barrier in the case of gross release of radioactive material from the reactor fuel to the reactor cooling water and steam.
- Limit release of radioactive material to the plant environs by closing the primary containment barrier in the case of a major leak from the nuclear system inside the primary containment.

4.6.2 SAFETY DESIGN BASES

The main steam isolation valves (MSIVs), individually or collectively:

- Close the pipelines within the time established by design basis accident (DBA) analysis to limit the release of reactor coolant or radioactive material.
- Close the pipeline when required despite single failure in either valve or in the attached controls which provide a high level of reliability for the safety function.
- Use separate energy sources as the motive force to close independently the redundant isolation valves in the individual steam line.
- Use local stored energy (compressed air and springs) to close the isolation valves in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure.
- Be able to close the pipelines, either during or after seismic loadings, to assure isolation if the nuclear system is breached.
- Have the capability for testing during normal operating conditions to demonstrate that the valves will function.

4.6.3 DESCRIPTION

Two MSIVs are welded in a horizontal run of each of the four main steam pipes, with one valve as close as possible to the primary containment barrier and inside it, and the other just outside the barrier. When they are closed, the valves form part of the nuclear system process barrier for openings outside the primary containment, and part of the primary containment barrier for nuclear system breaks inside the containment.

The description and testing of the controls for the MSIVs are included in section 7.3, Primary Containment and Reactor Vessel Isolation Control System. The circuitry provided to permit slow closure testing on the MSIVs is depicted on drawing no. S-15247. During slow closure testing, the normal fast closure circuitry remains energized and is not affected by the slow closing circuitry. Testing of a representative MSIV is described in the document "Design and Performance of General Electric Boiling Water Reactor Main Steam Isolation Valves," Appendix 5750 (March 1969).

Figure 4.6-1 depicts a MSIV. Each valve is a "Y" pattern, 24-in. globe valve connected to a matching 24-in. pipe. The normal steam flowrate through each valve is 2.91×10^6 lb/h. The main disc or poppet is attached to the lower end of the stem and moves in guides at a 45° angle from the inlet pipe. Normal steam flow tends to close the valve, and the higher inlet pressure increases the closing force. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve the differential pressure forces on the poppet. Valve stem travel is sufficient to give a flow area past the wide open poppet approximately equal to the seat port area. The poppet travels ~ 90% of the valve stem travel, and the last 10% of travel closes the pilot hole. A helical spring between the stem and the poppet keeps the pilot hole open when the poppet is off its seat, but failure of the spring will not prevent closure of the valve. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the MSIV in a direction which tends to hold the valve closed.

The diameter of the poppet seat is approximately the same size as the inside diameter of the pipe, and the 45-degree angle permits the inlet and outlet passage to be streamlined. This design minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at rated flow is ~ 6 psi. The valve stem penetrates the valve bonnet through a stuffing box which has replaceable packing. The bonnet and body flange are prepared for seal welding and can be welded together in case leaks develop after extensive service.

The upper end of the stem is attached to an air cylinder and a hydraulic dashpot. The air cylinder is to open and close the valve, and the hydraulic dashpot is used to control speed. A valve in the hydraulic return line bypassing the dashpot adjusts speed, and the valve closing time is adjustable between 3 and 10 s.

The hydraulic dashpot is a closed system charged with a fluid which is forced through a restricting orifice to provide resistance to motion of the valve stem. The principle of operation is similar to an automotive shock absorber.
Materials of construction are steel (cylinder tube, rod, and piston) and "Viton" seals. The fluid is GE Silicon, type SF 1147.

The dashpot assembly is designed, manufactured, assembled, inspected, and tested as safety-related parts or purchased as a commercial grade component and dedicated for safety-related application.

No specific qualification tests were performed on the dashpot assemblies regarding time, temperature, and radiation. Materials of construction are, by commercial designation, suitable for the expected operating conditions.

Periodic maintenance and closure time testing of MSIVs (with repair as needed) is intended to preclude malfunction of the equipment. Throttling orifices are of relatively generous proportions and not normally subject to plugging.

Loss of hydraulic fluid may cause faster closing of the MSIVs with the effect dependent upon the amount of fluid lost. If only one of the steam lines is isolated in less than the specified time, the effect on the steam supply system is not significant.

The air cylinder is supported on large shafts screwed and pinned into the valve bonnet. The shafts are also used as guides for the helical springs used to close the valve in the event that the air pressure is not enough to close the MSIV. The springs exert downward force on the spring seat member which is attached to the stem. Spring guides prevent scoring in normal operation and prevent binding if a spring breaks. The spring seat member is also closely guided on the support shafts and rigidly attached to the stem to control any eccentric force in case a spring breaks.

The motion of the spring seat member actuates switches at fully open, 90% open, and fully closed valve positions. Starting from the full open position, switches at the 90% open position turn on the close light, while the open light stays on for valve testing, and initiate reactor scram if several valves close simultaneously. (See section 7.2, Reactor Protection System.)

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder, and it contains the pneumatic ac and dc control valves used to open and close the main valve and exercise it at slow speed. Remote manual switches in the control room enable the operator to operate or close each valve at fast speed (3 to 10 s) or at the slow speed (45 to 60 s) for exercising or testing purposes.

Operating air is supplied to the valves from the plant air system through a check valve. An air tank between the control valve and the check valve provides backup operating air.

High-pressure, high-temperature steam will flow through the valves. The valve is designed to accommodate saturated steam at 1250 psig and 575°F with a rapid flow increase to 200% of rated flow. Any additional increase is limited by the venturi flow restrictor upstream of the valves.

During approximately the first 75% of closing, the valve has little effect on flow reduction, because the flow is choked by the venturi restrictor upstream of the valves. After the valve is more than ~ 75% closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valve is a minimum of 40-years service at the specified operating conditions. Aging management programs (HNP-2-FSAR subsections 18.2.1, 18.2.9, 18.2.14, and 18.4.5) monitor the condition of the MSIVs so that actions are taken to provide reasonable assurance that these components are capable of performing their intended functions for 40 years and beyond. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.

Design specification ambient conditions for normal plant operation are 135°F normal temperature, 150°F maximum temperature, and 100% humidity in a radiation field of 15-R/h gamma and 25-Rad/h neutron plus gamma continuous for design life. In fact, the inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions which are considerably less severe.

To resist sufficiently the response motion from the design basis earthquake, the MSIV installations are designed as Seismic Class 1 equipment. The valve assembly is manufactured to withstand the design basis seismic forces applied at the mass center, assuming the cylinder/spring operator is cantilevered from the valve body, and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are considered to act simultaneously and are combined. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads including the operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress as set forth in the applicable codes. The parts of the MSIVs which constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested essentially as described in appendix A.

4.6.4 SAFETY EVALUATION

The safety objectives of the MSIVs are to limit release of radioactive material by closing the nuclear system process barrier and the primary containment barrier and to limit the loss of reactor cooling water in case a major steam leak occurs outside the primary containment.

In a direct cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the reactor containments. Radioactive material in the steam are released to the environs through process openings in the steam system or they can escape from accidental openings. A large break in the steam system can void the water from the reactor core faster than it is replaced by feedwater. The analysis of a complete sudden steam line break outside the primary containment is provided in HNP-2-FSAR chapter 15, Safety Analysis. It shows that the fuel barrier is protected against loss of cooling if MSIV closure takes 5.5 s or less (including as much as 0.5 s for the instrumentation to initiate valve closure after the break). The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (~ 3 s) of the MSIVs is also shown to be satisfactory in HNP-2-FSAR chapter 15. The switches on the valves initiate reactor scram when several valves are more than 10% closed. The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel-cladding temperature will be insignificant. The transient is less than that from sudden closure of the turbine stop valves (in ~ 0.1 s) coincident with postulated failure of the turbine bypass valves to open. No fuel damage results.

The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high-pressure differentials and fluid flows and with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. Dynamic tests with a 1-in. valve show that the analytical method is valid. A full-size, 20-in. valve was tested in a range of steam/water blowdown conditions simulating postulated accident conditions. (See reference 4.)

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests:

A. To verify its capability to close between 3 and 10 s, each valve is tested at rated pressure (1000 psig) and no flow. The valve is stroked several times, and the closing time is recorded. The valve is closed by spring only and by the combination of air cylinder and springs.

B. Leakage is measured with the valve seated and back seated. Seat leakage is measured by pressurizing the upstream side of the valve. The specified maximum seat leakage, using cold water at design pressure is 2 cc /h/in. of nominal valve size. In addition, an air seat leakage test is conducted using 50-psi pressure upstream. Maximum permissible leakage is 1/10 sf^3/h/in. of nominal valve size. There must be no visible leakage from stem packing at design pressure. The valve stem is operated a minimum of three times from the closed position to the open position, after which there must be no visible packing leakage.

C. Each valve is hydrostatically tested in accordance with the requirements of the American Society of Mechanical Engineers Nuclear Pump and Valve Code. During valve fabrication, nondestructive tests and examinations are extensive. These tests include radiographics, and liquid penetrant or magnetic particle examinations of casting, forgings, welds, hardfacings, and bolts.

D. The spring guides, the guiding of the spring seat member on the support shafts, and the rigid attachment of the seat member assures proper alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying steam force near the bottom of the poppet. Clearance between the poppet and its guides is such that some cocking of the poppet or warpage of the seat can be tolerated and a seal still achieved.

After the valves are installed in the nuclear system, each valve is tested several times in accordance with the preoperational and startup test procedures.

Two MSIVs provide redundancy in each steam line so either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve and the outside valve, and their respective control systems, are separated physically. Considering the redundancy, the mechanical strength, closing forces, and leakage tests discussed above, the MSIVs limit the release of reactor coolant or radioactive material within the margins evaluated in HNP-2-FSAR section 15.2.

The MSIVs and their installation are designed as Seismic Class 1 equipment.

The design of the MSIV was analyzed for earthquake loading. These loads are small compared with the pressure and operating loads which the valve components are designed to withstand. The cantilevered support of the air cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading is negligible at the joints between the support shafts and the valve bonnet.

Electrical equipment that is associated with the MSIVs and that operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the MSIVs. The design and purchase specifications for the environment are severe (subsection 4.6.3); i.e., 135°F normal and 150°F maximum ambient temperatures, 100% humidity, 40-year design life at operating conditions, 2050 operating cycles, and 15-R/h gamma and 25-Rad/h combined gamma and neutron radiation during nuclear system operation. These specifications were reviewed and determined to be acceptable and bounding for the renewed license term.

Under the accident conditions, ambient pressure increases to ~ 50 psig, and each valve is required to operate following 20-s exposure to this condition. The valve closing, completed in 3 to 10 s after the DBA occurs well before higher pressure or temperature might impair the ability of the valves to close.

The requirements of the purchase specifications; review and approval of the equipment design and vendor drawings; extensive control of materials, fabrication procedures, fabrication tests, nondestructive examinations, shop tests, preoperational and startup tests of the installed valves; and prescribed periodic inspections and tests during the plant life ensure operation of the valves under normal operating conditions and in the postulated accident environments.

4.6.5 INSPECTION AND TESTING

The MSIVs may be tested during plant operation, and tested and inspected during refueling outages. The test operations are listed below:

A. The MSIVs may be tested and exercised individually to the 90% open position without reducing reactor power, because the valves still pass rated steam flow when they are 90% open.

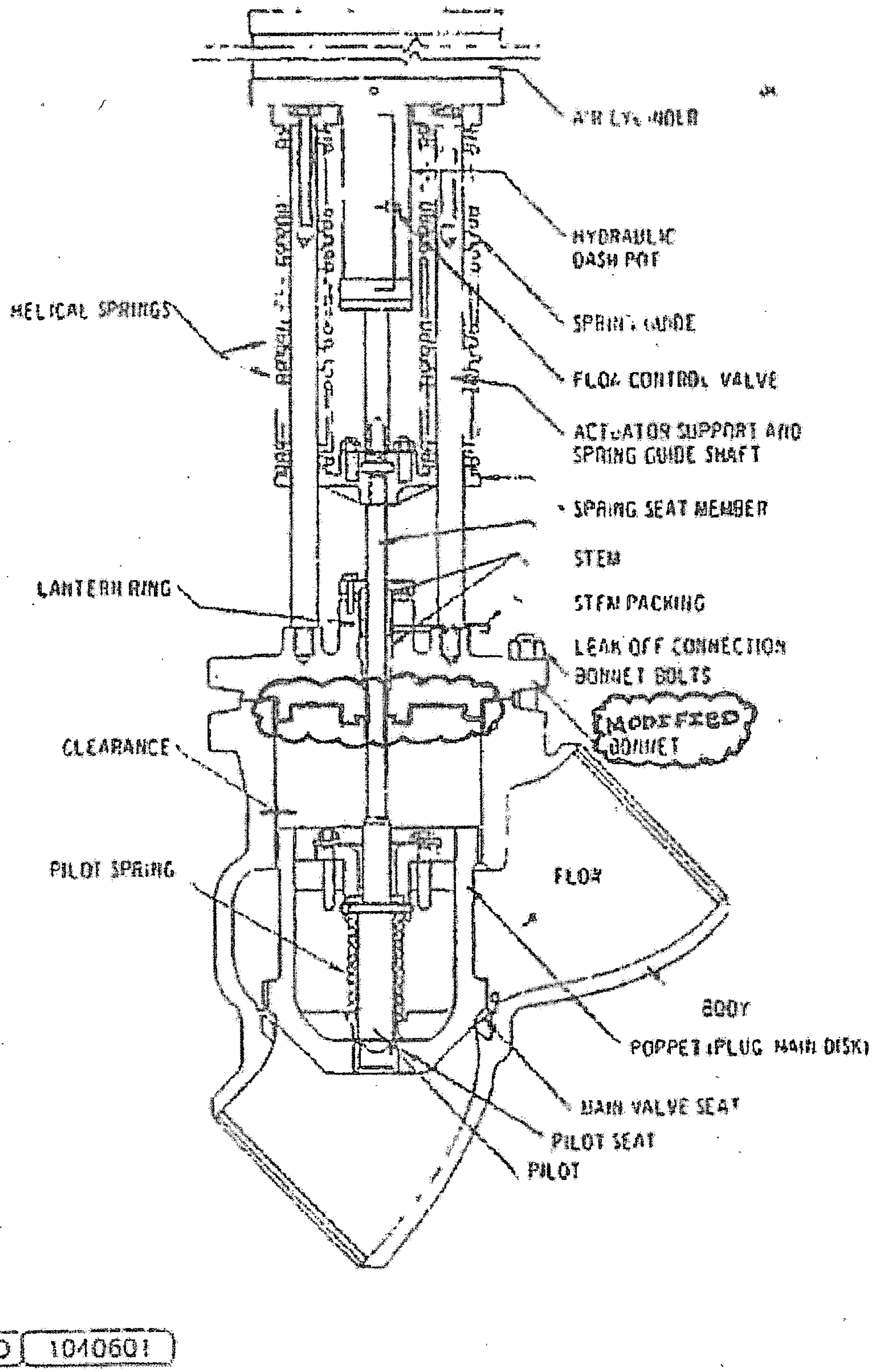
B. The MSIVs may be tested and exercised individually to the fully closed position by reducing reactor power to 75% full power.

C. Standard leakage tests are performed in accordance with the plant Technical Specifications.

REFERENCES

1. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

2. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.



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SOUTHERN COMPANY *Energy to Serve Your World*	SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	MAIN STEAM LINE ISOLATION VALVE Figure 4.6-1

4.7 <u>REACTOR CORE ISOLATION COOLING SYSTEM</u>

4.7.1 SAFETY OBJECTIVE

The reactor core isolation cooling (RCIC) system provides core cooling during reactor shutdown by pumping makeup water into the reactor pressure vessel (RPV) in case of a loss of flow from the main feed system and is activated in time to preclude conditions which lead to inadequate core cooling. The current safety analysis report[1] and reactor operating pressure increase (ROPI) project report[2] demonstrate that the HNP-1 RCIC system can safely operate at a power level of 2804 MWt and 1060 psia.

4.7.2 SAFETY DESIGN BASES

A. The RCIC system is capable of maintaining sufficient coolant in the reactor vessel in case of a loss of main feedwater flow.

B. Provisions are made for automatic and remote manual operation of the RCIC system.

C. Components of the RCIC system are designed to satisfy Seismic Class 1 design requirements.

D. To provide a high degree of assurance that the RCIC system will operate when necessary, the power supply for the RCIC system comes from immediately available and highly reliable energy sources.

E. To provide a high degree of assurance that the system will operate when necessary, a provision is made so that periodic testing can be performed during unit operation.

4.7.3 DESCRIPTION

The RCIC system consists of a steam-driven turbine pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. Table 4.7-1 summarizes the design data of the turbine pump unit. Schematic diagrams are included on drawing nos. H-16334 and H-16335.

The steam supply to the turbine comes from the reactor vessel. The steam exhaust from the turbine dumps to the suppression pool. The pump can take suction from the demineralized water in the condensate storage tank (CST) or from the suppression pool. The pump discharges either to the feedwater line or to a full-flow return test line running to the CST. A minimum flow bypass line to the suppression pool provides pump protection. The makeup water is delivered into the reactor vessel through a connection to the feedwater line,[a] and it is distributed within the reactor vessel through the feedwater sparger.

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a. The RCIC system discharges into a different feedwater line than the HPCI system.

Cooling water for the RCIC system turbine lube oil cooler and gland-seal condenser is supplied from the pump discharge.

Following any reactor shutdown, steam generation continues due to heat produced by the radioactive decay of fission products. Initially, the rate of steam generation can be as high as ~ 6% of rated flow and is augmented during the first few seconds by delayed neutrons and by some of the residual energy stored in the fuel. The steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, through the relief valves to the suppression pool. The fluid removed from the reactor vessel can be furnished entirely by the feedwater pumps or partially by the control rod drive (CRD) system which is supplied by the CRD feed pumps. If makeup water is required to supplement these sources of water, the RCIC system turbine pump unit starts automatically upon receipt of a RPV water level 2 signal (drawing no. H-19956) or is started by the operator from the control room by remote manual controls. A signal at level 2 also energizes the high-pressure coolant injection (HPCI) system (chapter 6, Emergency Core Cooling System). The RCIC system delivers its design flow within 45 s after actuation. To limit the amount of fluid leaving the reactor vessel, an RPV low water level 1 signal actuates closure of the main steam isolation valves. The RPV water level instrumentation is part of the analog transmitter trip system which is discussed in section 7.18.

For anticipated operational occurrences, the RCIC system has a makeup capacity sufficient to prevent the reactor vessel water level from decreasing to the level where the core is uncovered without the use of the emergency core cooling system (HNP-2-FSAR chapter 15, Safety Analysis). Three pump suction valves are provided in the RCIC system; one valve allows pump suction from the CST while the other two allow water to be taken from the suppression chamber. The CST is the preferred source. All three valves are operated by dc motors.

Upon receipt of a RCIC system initiation signal, the RCIC pump takes suction from the CST. If the water level in the CST falls below a preselected level, the suppression chamber suction valves automatically open, and the CST suction valve automatically closes. Two level switches are used to detect the CST low water level condition. Either switch can cause the suppression chamber suction valves to open and the CST suction valve to close. The suppression chamber suction valves also open automatically if a high water level is detected in the chamber. Two level switches monitor the water level, and either switch can initiate opening of the suppression chamber suction valves.

Two dc motor-operated RCIC pump discharge valves in the pump discharge pipeline are provided (drawing nos. H-16334 and H-16335). Both valves are arranged to open upon receipt of either one of the RCIC system initiation signals. One of the pump discharge valves closes automatically upon receipt of a turbine trip signal; the other valve remains open after RCIC system initiation until closed by the operator in the main control room.

To assure net positive suction head (NPSH) to the pump, the turbine pump assembly is located below the level of the CST and below the minimum water level in the suppression pool. Pump

NPSH requirements are satisfied by providing adequate suction head and adequate suction line size. System performance under various operating conditions is shown on drawing no. S-15066. All components necessary to initiate operation of the RCIC system are completely independent of auxiliary ac power, plant service air, and external cooling water systems; they require only dc power from a plant battery to operate the valves, the vacuum pump, and the condensate pumps. The power source for the turbine pump unit is the steam generated in the reactor pressure vessel by decay heat in the core. The steam is piped directly to the turbine, and the turbine exhaust is piped to the suppression pool.

If for any reason the reactor vessel is isolated from the main condenser, pressure in the reactor vessel increases; however, it is limited by automatic or remote manual actuation of the relief valves. Relief valve discharge is piped to the suppression pool. Throughout the period of RCIC system operation, the exhaust from the RCIC system turbine and relief valve discharge, being condensed in the suppression pool, results in a temperature rise in the pool. During this period, residual heat removal (RHR) heat exchangers are used to maintain pool water temperature within acceptable limits.

To assure that personnel access areas are not restricted during RCIC system operation, the RCIC system turbine pump unit is located in a shielded area. Steam supply valve 1E51-F045 and the turbine controls (drawing nos. H-19955 through H-19962) provide for automatic shutdown of the RCIC system turbine upon receipt of the following signals:

- Reactor vessel water level 8 to indicate that core cooling requirements are satisfied.
- Turbine overspeed to prevent damage to the turbine and turbine casing.
- RCIC isolation signal from logic A or B.
- Pump low-suction pressure to prevent damage to the turbine pump unit due to loss of cooling water.
- Turbine high-exhaust pressure to indicate turbine or turbine control malfunction.
- Manual trip.

If an RPV water level 2 initiation signal is received after the turbine is shut down due to an RPV water level 8 signal, the system is capable of automatic restart.

Since the steam supply line in the RCIC system turbine is a primary containment boundary, certain signals automatically isolate this line and cause shutdown of the RCIC system turbine. Automatic shutdown of the steam supply (drawing nos. H-19959 and H-19960) is described in section 7.3, Primary Containment and Reactor Vessel Isolation Control System. Operating logic for all other valves is shown on drawing nos. H-19955 through H-19962.

The turbine control system is positioned by the demand signal from a flow controller, and it satisfies a twofold purpose:

- To limit the turbine pump speed to its maximum normal operating value.

- To position the turbine governor valve as required to maintain constant pump discharge flow over the pressure range of system operation.

The functional control logics involved with the RCIC turbine start sequence are given on drawing no. H-19956. The RCIC initiation signal actuates motor-operated steam supply valve 1E51-F045. In order to reduce the rapid transient on the RCIC turbine, the steam supply valve is equipped with a special contour plug designed to limit steam flow into the turbine during the initial 45% of valve opening. This reduces the possibility of turbine overspeed occurring during the start sequence and is within the 45-s delay assumed in the safety analysis.

The RCIC system piping and equipment are designed in accordance with appendix A.

RCIC system operation during a station blackout event is discussed in HNP-2-FSAR section 8.4.

4.7.4 SAFETY EVALUATION

To provide a high degree of assurance that the RCIC system will operate when necessary and in time to provide adequate core cooling, the power supply for the system is taken from energy sources of high reliability and immediate availability. There are no transients in which the RCIC system must act in conjunction with the HPCI system in order to limit plant parameters to acceptable levels. The capability of testing during plant operation gives added assurance. Evaluation of instrumentation reliability for the RCIC system shows that a failure of a single initiating sensor will neither prevent the system from starting nor inadvertently start the system. Furthermore, there is no safety significance arising from an RCIC valve interlock failure on the RCIC test line.

The RCIC system in the standby mode is arranged with the pump suction source from the CST. The test return line is closed by the RCIC valve 1E51-F022 and HPCI valve 1E41-F011, and the suppression pool suction is closed by the redundant valves 1E51-F029 and 1E51-F031. Also, there is no automatic logic to open the RCIC test return line.

A. To inadvertently pump suppression pool water into the CST by the RCIC system, the following events must occur:

    - Manually open suppression pool suction valves 1E51-F029 and 1E51-F031 and test return valves 1E51-F022 and 1E41-F011.

    - Manually start the RCIC turbine.

    - Fail the redundant logic from the suppression pool suction valves 1E51-F029 and 1E51-F031 to common test return valve 1E51-F022.

With the assumption that the test return valve 1E51-F022 fails to close, it should be adequate and safe to rely on procedural control to prevent the simultaneous occurrence of the other five events.

B. During RCIC system operation, the only time the suppression pool suction source is manually selected is in the improbable event that condensate storage source was lost. In this situation, suppression pool water would be injected into the reactor vessel, and generated steam would be returned to the suppression pool by either the relief valves or the RCIC turbine exhaust. There would be no net change in inventory between the reactor vessel and the suppression pool. Note that with RCIC system initiation, an auto close signal is sent to the normally closed test return valve 1E51-F022. Simultaneously and occurring at the same RPV level, an independent auto close signal is sent to the redundant test return valve 1E41-F011 by the HPCI system initiation. Therefore, there is no single failure which would allow suppression pool water to be pumped to the CST.

C. The potential of feedwater pressure on the RCIC system test line to the CST is independent of the RCIC pump suction source. For this reason, the RCIC system test line is a high-pressure line which ties into the HPCI system test line upstream of the HPCI valve 1E41-F011. The HPCI system test line, out to and including valve 1E41-F011, is also a high-pressure line. Both HPCI and RCIC system test lines, out to and including 1E41-F011, are capable of withstanding full feedwater pressure. There are no valves in the low-pressure piping downstream of 1E41-F011, and there is no way that feedwater pressure can overpressurize the RCIC system test return piping to the CST.

D. Detailed design modifications of the start bypass line are documented in General Electric Licensing Topical Report NEDO-22217A.

The design of the RCIC system is in accordance with appendix A.

4.7.5 INSPECTION AND TESTING

A design flow functional test of the RCIC system is performed during plant operation by taking suction from the demineralized water in the CST and discharging through the full-flow test return line back to the CST. During the test, the discharge valve to the feedline remains closed and reactor operation is undisturbed. Control system design provides automatic return from the test mode to the operating mode if system initiation is required during testing. Inspection and maintenance of the turbine pump unit are conducted in accordance with manufacturer's instructions. Valve position indicators and instrumentation alarms are displayed in the control room.

“A gas accumulation monitoring and trending process for Hatch Unit 1 and Unit 2, ECCS (HPCI, RHR, Core Spray), Containment Spray and RCIC Systems has been established to meet the requirements of NRC Generic Letter 2008-01.”

REFERENCES

1. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

2. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 4.7-1

RCIC SYSTEM TURBINE AND PUMP DESIGN DATA[a]

Pump

Number required - 1
Capacity - 100%

Developed Head

2880 ft at 1170-psia reactor pressure
525 ft at 165-psia reactor pressure

Flowrate

Injection flow - 400 gal/min
Cooling water flow - 16 gal/min
Total pump discharge - 416 gal/min
NPSH - 20 ft (minimum)

Turbine

Number required - 1
Capacity - 100%
Low-steam pressure cutoff - 50 psig
~ 500 high pressure at 1170-psia reactor pressure
Exhaust pressure - 15-25 psi

a. For piping and equipment design temperature and pressure, see the pressure temperature index on drawing no. H-16334.

4.8 RESIDUAL HEAT REMOVAL SYSTEM

4.8.1 POWER GENERATION OBJECTIVE

The residual heat removal (RHR) system provides the means to meet the following power generation objectives:

- Remove decay and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed.

- Supplement the spent-fuel pool cooling and cleanup system capacity when necessary to provide additional cooling capacity.

The current safety analysis report[(1)] and reactor operating pressure increase (ROPI) project report[(2)] demonstrate that the HNP-1 RHR system can safely operate at a power level of 2804 MWt and 1060 psia.

4.8.2 POWER GENERATION DESIGN BASIS

The RHR system is designed with enough heat removal capacity so that the reactor can be cooled to a temperature at which refueling can commence in a reasonably short time after cooldown has commenced.

4.8.3 SAFETY OBJECTIVE

The objective of the RHR system is to restore and maintain the coolant inventory in the reactor vessel so that the core is adequately cooled after a loss-of-coolant accident (LOCA). The RHR system also provides containment cooling so that condensation of the steam resulting from the blowdown due to the design basis LOCA is ensured.

A new objective for the RHR containment spray mode has been added to remove airborne particulates in the drywell and to reduce the temperature and pressure of the primary containment atmosphere post-LOCA. Crediting this function was added as part of the implementation of an alternative source term (AST), reference HNP-2-FSAR subsection 15.1-11.

4.8.4 SAFETY DESIGN BASES

A. The RHR system [low-pressure coolant injection (LPCI) mode] acts automatically, in combination with the other emergency core cooling system (ECCS) subsystems, to restore and maintain the coolant inventory in the reactor vessel such that the core is adequately cooled to preclude fuel-cladding temperature in excess of 2200°F following a design basis LOCA.

B. The RHR system, in conjunction with the other ECCS subsystems, has such diversity and redundancy that only a highly improbable combination of events could result in their inability to provide adequate core cooling.

C. A source of water for restoration of reactor vessel coolant inventory is located within the primary containment in such a manner that a closed cooling water path is established.

D. To provide a high degree of assurance that the RHR system operates satisfactorily during a LOCA, each active component is capable of being tested.

E. The functional components of the RHR system are designed to satisfy Class 1 seismic requirements.

F. Provision is made so that residual heat removal service water (RHRSW) can be pumped directly into the RHR system.

4.8.5 SUMMARY DESCRIPTION

The RHR system is designed for six modes of operation to satisfy all the objectives and bases. The modes are summarized in table 4.8-1.

The major equipment of the RHR system consists of two heat exchangers and four main system pumps. Table 4.8-2 summarizes the design data of the RHR system. The RHRSW system (section 10.6) provides cooling water to the RHR exchangers. A process diagram of the RHR system is shown on drawing no. S-15305. Process data, showing the six modes of RHR operation, are tabulated on drawing no. S-15304. A description of the controls and instrumentation is presented in section 7.4. A description of the RHR system equipment (LPCI mode) operating in conjunction with other ECCS equipment to protect the core during a LOCA is presented in chapter 6.

There are four lines in the RHR system where overpressure protection is provided by isolation valves. The suction line to the RHR pumps is isolated from the reactor by two 20 in.-motor-operated valves. These valves are operated by independent control systems which automatically close the valves on a reactor pressure in excess of the pressure allowed for shutdown cooling. Furthermore, the pressure interlocks automatically close these valves and prevent them from being opened initially when the reactor pressure is in excess of that allowed for the shutdown cooling mode.

The lowest design pressure of the protected suction piping and valves is 220 psig. The pump discharge piping (design pressure of 375 psig) and the RHR heat exchanger (design pressure of 450 psig) are also protected from overpressurization during shutdown cooling operation by these reactor pressure interlocks on the suction valves. Each of the two pump discharge-to-recirculation loop lines has one check valve (24-in. for loop A and 18-in. for loop B) and one 24-in. motor-operated valve. Positioning of the motor-operated valve is indicated in the control room. The motor-operated valve is normally closed during reactor operation and cannot be opened (pressure switch interlock) against excessive pressure. The lowest design pressure of the protected discharge piping and valves is 375 psig.

Since each of the lines in the RHR system has two isolation valves in series with independent control, a single operator error or equipment malfunction can prevent one but not both of the valves from providing the overpressure protection. Since the failure of one valve to provide overpressure protection does not preclude protection by the other valve, the pressure interlock on one valve need not meet the single-failure criteria. Small relief valves are provided in each line to handle closed valve leakage. If the isolation valves fail to provide overpressure protection and overpressurization occurred, splitting of pipe sections near welds might be expected.

The RHR pumps are sized on the basis of the required flow during the LPCI mode of operation. The RHRSW pressure at the tube side outlet of the RHR heat exchangers is greater than the reactor coolant water pressure at the shell side during shutdown cooling and containment cooling modes of operation. This criterion ensures reactor coolant radioactivity is not released to the RHRSW in case of a leak in the heat exchanger tubes. The heat exchangers are sized on the basis of the required heat load during the shutdown cooling mode. A summary of the design requirements of RHR pumps and the RHR heat exchangers is presented in detail on drawing nos. S-15304 and S-15305.

Provision is made in the shutdown cooling piping circuit for making connection to the spent-fuel pool cooling system (drawing no. S-15305) so that the RHR heat exchangers may be used to assist spent-fuel pool cooling when a potential LPCI requirement does not exist (HNP-2-FSAR subsection 9.1.3).

One loop consisting of one heat exchanger, two RHR pumps in parallel, and associated piping is physically separated and protected from the second loop to minimize the possibility of a single physical event causing the loss of the entire system. The design, fabrication, and inspection requirements are stated in appendix A.

The RHR system equipment piping and support structures are designed to Class 1 seismic criteria.

4.8.6 LPCI MODE

The LPCI mode is an integral part of the RHR system. It operates to restore and maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude fuel-clad temperatures in excess of 2200°F and subsequent energy release due to a metal-water reaction. The LPCI system operates in conjunction with the high-pressure coolant injection system, the automatic depressurization system, and the core spray (CS) system to achieve this goal.

A detailed discussion of the requirements and response of the equipment which operates during LPCI for a LOCA may be found in chapter 6. A detailed discussion of the requirements and response of the controls and instrumentation of LPCI during a LOCA may be found in section 7.4.

During LPCI operation, the RHR pumps take suction from the suppression pool and discharge into the reactor vessel core region through both of the recirculation loops. Spillage through the LOCA break is contained by the drywell and returned to the suppression pool via the pressure suppression vent lines. Flow in the broken loop does not reach its expected value until the recirculation discharge valve has fully closed. A minimum flow bypass line to the suppression pool is provided so that the RHR pumps are not damaged when operating with closed discharge valves.

Service water flow to the RHR heat exchangers is not required immediately after a LOCA because heat rejection from the containment is not necessary during the time it takes to flood the reactor. The RHR pumps and the associated automatic motor-operated valves for each loop receive power from different emergency ac buses. Similarly, control power for each LPCI loop comes from different dc buses (sections 8.4 and 8.5.)

4.8.6.1 Plant Standby Coolant Supply

A cross-tie line is provided between the RHRSW system and the LPCI system so that RHR service water may be pumped directly into the reactor vessel or into the containment via the containment spray headers (drawing no. S-15305).

4.8.7 CONTAINMENT SPRAY MODE

The containment spray mode is an integral part of the RHR system and is used to remove airborne particulates in the drywell and to reduce the temperature and pressure of the primary containment atmosphere post-LOCA. The containment spray mode can be initiated manually after the LPCI cooling requirements have been satisfied. An interlock is provided so that the operator does not inadvertently initiate containment spray before LPCI requirements are met (section 7.4).

With the RHR system in the containment spray mode of operation, the RHR pumps are aligned to pump water from the suppression pool through the RHR heat exchangers where heat is transferred to the RHRSW system. The cooled water is diverted to spray headers in the drywell and some of this flow may be diverted to the header above the suppression pool. The spray in the drywell condenses any steam that may exist in the drywell, thereby lowering containment pressure and temperature. The spray also removes airborne particulates in the drywell. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent lines where it overflows and drains back to the suppression pool. Approximately 5% of the RHR flow can be directed to the suppression chamber spray ring to cool any noncondensable gases collected in the free volume above the suppression pool.

The suppression pool cooling and torus spray modes are periodically used during an operating cycle. It may be necessary to place the suppression pool cooling mode in service as the pool temperature increases during the summer months. Also, torus spray may be used to reduce torus pressure if, for example, an SRV is leaking during an operating cycle. If a LOCA signal is received while operating in either one or both modes, the LPCI response will not be adversely affected.

Primary containment pressure response following a design basis LOCA with and without the containment spray mode and with various combinations of RHR pumps, RHR heat exchangers, and RHRSW pumps is discussed in detail in HNP-2-FSAR subsection 6.2.3.

4.8.8 (Deleted)

4.8.9 SHUTDOWN COOLING MODE

The shutdown cooling mode is placed in operation during a normal shutdown and cooldown.

The initial phase of a normal nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser with the main condenser acting as the heat sink. Reactor cooldown is then completed by pumping reactor coolant with the RHR pumps from one of the recirculation loops through the RHR heat exchangers, where cooling takes place by transferring heat to the RHRSW system. Reactor coolant is returned to the reactor vessel via a recirculation loop.

The shutdown cooling subsystem is capable of completing cooldown to 125°F in ~ 20 h and maintaining the nuclear system at 125°F so that the reactor can be refueled and serviced.

After the decay heat levels have subsided, the entire shutdown cooling load can be shifted to one RHR heat exchanger, leaving the other available for other cooling loads.

4.8.10 SAFETY EVALUATION

The LPCI mode acts in conjunction with the other ECCS subsystems; therefore, the safety evaluation can be found in section 6.4. The safety evaluation of the controls and instrumentation for LPCI is provided in section 7.4.

An interlock exists in the logic for the RHR shutdown cooling suction valves, which are closed during power operation, to prevent opening of the valves above a preset pressure setpoint (table 7.3-2 and drawing no. H-19937). This setpoint is selected to assure that pressure integrity of the RHR system is maintained. Administrative operating procedures require the operator to close these shutdown cooling valves prior to pressure operation. However, as a backup, the interlock automatically closes these valves when the pressure setpoint is reached. Double indicating lights are provided in the control room for valve position indication.

4.8.11 INSPECTION AND TESTING

A design flow functional test of the RHR pumps is performed during normal plant operation by taking suction from the suppression pool and discharging through the test lines back to the

suppression pool. The discharge valves to the reactor recirculation loops remain closed during this test and reactor operation is undisturbed. This is designated as the test mode.
An operational test of the discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested and then operating the upstream valve. The discharge valves to the containment spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All these valves can be actuated from the control room. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing.

Testing of the sequencing of the LPCI mode of operation is performed at the frequency, under the plant conditions, and to the extent stipulated in the Technical Specifications and the Bases. Testing the operation of the valves required for the remaining modes of operation of the RHR system likewise is performed at the frequency, under the conditions, and to the extent stipulated in the Technical Specifications and the Bases.

Periodic inspection and maintenance of the RHR pumps, pump motors, and heat exchangers are carried out in accordance with the manufacturers' instructions.

A discussion of the availability of engineered safeguards and frequency of testing of equipment is presented in chapter 6.

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 4.8-1

SUMMARY OF RHR SYSTEM MODES OF OPERATION

Mode	Action	Function
LPCI	Accident safety	Restore and maintain reactor vessel water level after a LOCA.
Containment spray	Post-accident safety	Remove particulates in the drywell and limit temperature and pressure in the torus and drywell after a LOCA.
Suppression pool cooling[a]	Abnormal operation	Remove heat from the suppression pool water.
Shutdown cooling[a]	Planned operation	Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.
Minimum flow	Equipment protection	Prevent pump damage when operating against closed discharge valve.
Test	System test	Test RHR system during plant operation.

a. Containment cooling occurs when RHRSW and LPCI water (with or without containment spray water) is flowing through the RHR heat exchangers (subsection 14.4.3).

TABLE 4.8-2

RHR SYSTEM DESIGN DATA

Pump	
Number	4
Capacity (each)[(a)(b)]	7700 gal/min at 420 ft total dynamic head
Design pressure	450 psig
Design temperature	360°F
Net positive suction head at runout	< 24 ft
Heat Exchanger	
Number	2
Capacity (each in shutdown cooling mode)	50%
Design pressure (shell side)	450 psig
Design pressure (tube side)	450 psig
Design temperature (shell side)	400°F
Design temperature (tube side)	400°F
Heat exchanger	30.8×10^6 Btu/h with 85°F river water and 125°F reactor water

a. For pump flows in various modes of RHR operation, see drawing no. S-15304.

4.9 REACTOR WATER CLEANUP SYSTEM

4.9.1 POWER GENERATION OBJECTIVE

The reactor water cleanup (RWC) system maintains high reactor water purity to limit chemical and corrosive action, thereby limiting fouling and deposition on heat transfer surfaces. The RWC system also receives corrosion products to limit impurities available for neutron activation and resultant radiation from deposition of corrosion products.

The current safety analysis report[1] and reactor operating pressure increase (ROPI) project report[2] demonstrate that the HNP-1 RWC system can safely operate at a power level of 2804 MWt and 1060 psia.

4.9.2 POWER GENERATION DESIGN BASES

A. The design bases provide for the discharge of reactor water at reduced activity during startup and shutdown.

B. The design bases limit the heat loss and the fluid loss from the nuclear system.

4.9.3 DESCRIPTION

The RWC system (drawing nos. H-16188 and H-16189) provides continuous purification of a portion of the recirculation flow. The processed fluid is returned to the nuclear system, or to storage. Drawing nos. H-19963 and H-19964 present the functional control diagram for the RWC.

A regenerative heat exchanger is provided to limit heat loss from the nuclear system. The system can be operated at any time during planned operations.

The major equipment of the RWC system is located in the reactor building. It consists of pumps, regenerative and nonregenerative heat exchangers, and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation. Design data for the major pieces of equipment are presented in table 4.9-1.

Reactor coolant is removed from the reactor coolant recirculation system, cooled in the regenerative and nonregenerative heat exchangers, filtered, and demineralized and returned to the feedwater system through the shell side of the regenerative heat exchanger. Because the temperature of the filter-demineralizer units is limited (table 4.9-1), the reactor coolant must be cooled prior to processing in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the influent water to the effluent water. The effluent returns to the feedwater system. The nonregenerative heat exchanger cools the influent water further by transferring heat to the reactor building closed cooling water system. The nonregenerative heat exchanger is designed to maintain the lower temperature, even when the effectiveness of the regenerative heat exchanger is reduced.

The thermal effectiveness of the regenerative heat exchangers is reduced when excess water is being removed from the reactor vessel via the RWC system. A part of the flow from the filter-demineralizer is directed either to the main condenser (normal discharge) or to the radwaste system and is returned to storage instead of returning to the reactor via the regenerative heat exchanger.

The filter-demineralizer units are pressure precoat type filters using finely ground, mixed ion exchange resins as filter and ion exchange mediums. Spent resins are not regenerable and are sluiced from a filter-demineralizer unit to a resin receiver tank from which they are processed in the radioactive waste system.

To prevent resins from entering the reactor recirculation system, several protection features are employed:

- A strainer is installed on the outlet of each filter-demineralizer unit, which is provided with a high differential pressure alarm, indicative of resin buildup.

- On loss-of-power, the demineralizers isolate and the holding pump trips and remains inoperable upon restoration of power. The demineralizer isolation valves and holding pump trip circuits reset to allow the demineralizer to be returned to service only after a backwash/precoat operation has been performed.

- Additionally, each demineralizer isolates on system low flow if the flow through it drops from 75% of normal flowrate (76 gal/min) to 40% of normal flowrate (41 gal/min) in < 15 s. Again, a backwash/precoat operation must be performed to remove the isolation and return the demineralizer to service.

- When returning the system to service, slow pressurization of filter/demineralizers is manually executed via a bypass line around the inlet air-operated valves to prevent potential resin carryover to the reactor.

The demineralizers are equipped with a bypass line which will allow the RWC system to remain in service if a demineralizer is out of service for any reason.

In the event of system low flow or loss of flow, flow is maintained (except as noted previously) through each filter-demineralizer by its own holding pump. A sample point is provided upstream and downstream of each filter-demineralizer unit. The influent sample point is also used as the normal source of reactor coolant samples. Sample analysis indicates the effectiveness of the filter-demineralizer units.

Relief valves and instrumentation are provided to protect the equipment against over-pressurization and the resins against overheating. The system is automatically isolated for the reasons indicated when signaled by any of the following occurrences:

- High temperature downstream of the nonregenerative heat exchanger -- to protect the ion exchanger resins from damage due to high temperature.

- Reactor pressure vessel water level 2 - - to protect the core in case of a possible break in the RWC system piping and equipment (section 7.3.).

- Standby liquid control system actuation - - to prevent removal of the boron by the filter-demineralizers.

- High cleanup system ambient temperatures [part of the leak detection system (LDS)].

- Loss of power - - loss of flow allows the resin to fall from the filter elements.

- Low flow through the system (40% of normal flow) - - to prevent loss of resin from the filter-demineralizers.

- High temperature increase across the system ventilation ducts (part of the plant LDS).

- High change in system inlet flow in comparison to the system outlet flow (part of the plant LDS).

Operation of the RWC system is controlled from the main control room. Resin changing operations, which include backwashing and precoating, are controlled from a local control panel in the reactor building.

4.9.4 INSPECTION AND TESTING

Because the RWC system is normally in service during plant operation, satisfactory performance is demonstrated without the need for any special inspection or testing.

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 4.9-1

REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

Main Cleanup Recirculation Pumps

Number required	1 of 2 (1 spare)
Capacity (each)	100%
Discharge flow (per pump) at 533°F, 164 TDH	266 gal/min
Design temperature	drawing no. H-16188
Design pressure	drawing no. H-16188

Heat Exchangers

	Regenerative	Nonregenerative
Number required	3 of 3	2 of 2
Reactor coolant design flow/per unit (lb/h)	100,000	100,000
Shell side design pressure (psig)	1400	150
Shell side design temperature (°F)	564	370
Tube side design pressure (psig)	1400	1400
Tube side design temperature (°F)	564	564

Filter-Demineralizers

Number required	2 of 2
Capacity (each)	50%
Design flow/unit	101 gal/min
Effluent conductivity	< 0.1 μmho
Effluent (pH)	6.5 to 7.5
Effluent insolubles (ppb) - (measured as residue on 0.45 micron-filter paper)	< 10
Design temperature	150°F
Design pressure	1400 psig
Time to remove a unit from service, backwash, precoat, and return it to service	≤ 60 min

4.10 NUCLEAR SYSTEM LEAKAGE DETECTION AND LEAKAGE RATE LIMITS

The current safety analysis report[5] demonstrates that for HNP-1, the leak detection system setpoints for the nuclear system leakage detection system at a power level of 2804 MWt remain unchanged.

4.10.1 SAFETY OBJECTIVE

Reliable means are provided to detect and isolate leakage from the nuclear system process barrier and systems essential to safe plant shutdown before predetermined limits are exceeded.

4.10.2 SAFETY DESIGN BASES

A. Means are provided to detect abnormal leakage before the results of this leakage become unacceptable.

B. Means are provided to isolate abnormal leakage before the results of this leakage become unacceptable.

C. Limits are established on abnormal leakage so that corrective action can be taken before unacceptable results occur. The unacceptable results are as follows:

- A threat of significant compromise to the nuclear system process barrier.
- A leakage rate in excess of the coolant makeup capability to the reactor vessel.
- Flooding of equipment required for safe operation or shutdown of the plant.

Definitions:

Normal design leakage - Controlled quantity of fluid released from seals or sealing systems of piping components which are properly assembled and in good condition.

Abnormal leakage - Fluid released from a small crack or damaged seal in the nuclear system process barrier which has a low probability of rapid growth and does not exceed the guideline limits of Federal regulations with respect to accidents.

Gross leakage - Uncontrolled fluid released from a ruptured piping component at such a rate that the guideline limits of Federal regulations with respect to accidents could be violated if isolation is not affected.

4.10.3 DESCRIPTION

This subsection describes the leak detection systems (LDSs) which are provided to detect abnormal leakage from the nuclear system process barrier both inside and outside the primary containment and systems essential to safe plant shutdown, i.e., emergency core cooling system (ECCS). Also discussed in this subsection are nuclear system leakage rate limits and how they are established.

The systems which detect gross leakage resulting from a pipe rupture and initiate automatic isolation are considered as part of the reactor vessel and primary containment isolation control system and are discussed in section 7.3, Primary Containment and Reactor Vessel Isolation Control System. The controls available for manually initiating isolation are also discussed in section 7.3. In some cases, a LDS, which provides an automatic isolation signal, also provides an indication or alarm signifying abnormal leakage. In such cases, the indication or alarm function provided is discussed in this subsection.

4.10.3.1 Normal Design Leakage

The pump packing glands, valve stems, and other seals in systems, which are part of the nuclear system process barrier from which normal design leakage is expected, are provided with drains or auxiliary sealing systems. The valves and pumps in the nuclear system inside the drywell are equipped with double seals. Leakage from the primary recirculation pump seals is piped to the equipment drain sump as described in section 4.3, Reactor Recirculation System. Leakage from the main steam relief and safety valves is identified by temperature sensors which transmit to the main control room (MCR). Any temperature increase detected by these sensors above the drywell ambient temperature indicates valve leakage. Leakage from the reactor vessel head flange gasket is piped to a collection chamber and then to the equipment drain sump. The collection chamber filling time is periodically timed during plant operation and the flange gasket leakage rate is calculated.

Operational data from other plants indicate that the total normal identified leakage rate collected in the drywell equipment drain sump is ~ 3 to 4 gal/min and the total normal unidentified leakage rate collected in the drywell floor drain sump is ~ 0.5 gal/min for Hatch Nuclear Plant-Unit 1 (HNP-1).

A more detailed discussion is presented in section 7.8, Reactor Vessel Instrumentation. Thus, the leakage rates from the pumps, valve seals, and the reactor vessel head seal are measurable during operation of the plant. These leakage rates, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates.

4.10.3.2 Unidentified Leakage Rate

The unidentified leakage rate is that portion of the total leakage rate received in the drywell sumps not identified as described in paragraph 4.10.3.1. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack large enough to propagate rapidly. The unidentified leakage rate limit must be low because of the possibility that most of the unidentified leakage rate might be emitted from a single crack in the nuclear system process barrier.

A leakage rate of 150 gal/min has been conservatively calculated to be the minimum liquid leakage from a crack large enough to propagate rapidly. An allowance for reasonable leakage, which does not compromise barrier integrity and is not identifiable, is made for normal plant operation.

The unidentified leakage rate has been calculated to be 15 gal/min. This rate is far enough below the 150-gal/min leakage rate to allow time for corrective action to be taken before the process barrier could be significantly compromised. However, for added conservatism, the unidentified leakage rate limit has been established at a reduced value as indicated by the Technical Specifications.

The unidentified leakage rate is based on the calculated flow from a critical crack in a primary system pipe.

Statements concerning leakage rates are based on information from a pipe study report(1) that relates to a circumferential through wall crack in a pipe under pressure and bending. In the absence of experimental data, the pipe study report was based on analytical approximations of critical crack size and crack opening displacement. Experiments subsequently conducted by General Electric (GE)(2) and Battelle Memorial Institute(3) permit a more accurate analysis of the subject which generally substantiates the earlier conclusions.

4.10.3.3 Total Leakage Rate

Total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the control rod drive (CRD) and the reactor core isolation cooling (RCIC) systems and, independent of the feedwater system, normal ac power and the CSCSs. The CRD system supplies ~ 45 gal/min into the bottom of the reactor vessel, and the RCIC system can supply 400 gal/min through the feedwater sparger to the reactor vessel. The total leakage rate limit is conservatively established by the Technical Specifications at 30 gal/min within any 24-h period.

The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps. The equipment drain sump (500-gal capacity) and the floor drain sump (500-gal capacity), which collect all leakage, are each drained by two 50-gal/min pumps. The total leakage rate limit is set below the removal capacity of the two pumps in each sump because most of the total leakage could flow into one sump.

4.10.3.4 Leakage Detection Systems

The systems or parts of systems that contain water or steam coming from the reactor vessel or supply water to the reactor vessel and are in direct communication with the reactor vessel are provided with LDSs. Table 4.10-1 shows the systems in communication with the reactor vessel, the LDSs that monitor these systems, and the locations or areas monitored. The LDSs are schematically shown on figures 4.10-1 through 4.10-4. (For more detailed information, see also the piping and instrumentation diagram and the functional control diagram for the individual system.)

The following paragraphs describe each LDS or type of LDS and its instrumentation. In most cases, the same type of detection system is used in several locations.

4.10.3.4.1 Detection of Leakage Inside Drywell

Since the systems within the drywell share a common area, their LDSs are necessarily common. Each of the LDSs inside the drywell is designed with a capability to detect leakage less than established leakage rate limits.

A. Drywell Pressure Measurement

The primary containment is pressurized and maintained at a slightly positive pressure during reactor operation. The pressure fluctuates very slightly as a result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values indicates the presence of a system leak within the drywell.

B. Drywell Temperature Measurement

The primary containment cooling system recirculates the primary containment atmosphere through heat exchangers (air coolers) to maintain the primary containment at its design operating temperature of 135°F. The drywell average air temperature limit for normal operation is ≤ 150°F. The plant service water (PSW) system provides cooling water to the air coolers. An increase in the primary containment atmosphere temperature would increase the heat load on the air coolers and result in an increased temperature rise in the cooling water passing through the coils of the aircoolers.

Thus, the PSW temperature difference increase between inlet and outlet to the air coolers indicates the presence of a reactor coolant or steam leakage. Also, an increase in drywell ambient temperature rise above 135°F may indicate the presence of reactor coolant or steam leakage, providing the drywell coolers are in operation.

C. Drywell Floor Drain Sump Flow Measurement

The floor drain sump is provided with two sump pumps. A flow integrator is provided on the discharge header. The starting of each sump pump and high sump level are annunciated in the control room. The restarting frequency of a pump motor, in conjunction with the predetermined volume of liquid pumped out during each period, provides an alarm in the MCR indicating when the unidentified leakage rate limit is reached.

The normal design leakage collected in the floor drain sump consists of leakage from the CRDs, valve flange leakage, and cooling water leakage. This leakage is identified during preoperational tests. Additionally, the leakage from the reactor building closed cooling water system is identified during plant operation by changes in the surge tank level. Any increase above these identified values is detected by the floor drain sumps.

D. Drywell Equipment Drain Sump

The equipment drain sump is provided with two sump pumps. A flow integrator is provided on the discharge header. The starting of each sump pump and high-sump level are annunciated in the control room. The restarting frequency of a pump motor, in conjunction with the predetermined volume of liquid pumped out during each period, provides an alarm in the MCR indicating when the identified leakage rate limit is reached.

The normal leakage collected in the equipment drain sump consists of leakage from the reactor vessel head flange, the recirculation pump seals, the recirculation system valves, the RCIC system valves, the cleanup system valves, the shutdown system valves, the main steam isolation valves, and the CRD system valves. This leakage is identified during preoperational tests and any increase above these values is detected by monitoring the equipment drain sump discharge.

E. Fission Product Monitoring

The drywell fission products monitoring system provides a continuous air sampling of the drywell atmosphere through monitoring gross particulates, iodine, and noble gas activities. The system consists of an air pumping system and a fission products detecting and monitoring system. The monitoring system consists of an air particulate filter, a charcoal filter, a noble gas sample chamber and detectors all housed within a lead shield. A continuous air sample is drawn from the drywell passed through the detecting and monitoring system and returned to the drywell.

A fission products monitoring system is considered to be useful in supplementing the temperature, pressure, and flow-monitoring methods (from the drywell equipment and floor drain sumps).

It is expected to provide improved sensitivity to aid in determining the size and general source of leaks particularly with respect to gaseous (steam) leaks. Radioactivity is suitable for measuring steam leaks and can prove to be quite sensitive. For both liquid and gaseous leaks such a method appears to be useful in supplementing temperature, pressure, and flow-monitoring methods and, by providing additional information, to aid in deducing the size and general source of leaks. However, the radioactivity measurements should be used only to supplement the principal detection methods employing temperature, pressure, and flow measurement.

The fission product monitoring system contains a three-channel monitor--one for each function. The activity from each is displayed on a log ratemeter located in the control room.

4.10.3.4.2 Detection of Abnormal Leakage Outside Primary Containment

Outside the primary containment, the piping within each system monitored for leakage is in compartments or rooms separate from other systems, so that leakage may be detected in drains or by area temperature indications. Each of the leakage detection systems is designed to detect leakage rates less than the established leakage limits.

A. Room Ventilation or Standby Cooler Temperature

A differential temperature sensing system is installed in each room containing residual heat removal (RHR) system and reactor water cleanup (RWC) system equipment, as well as the vapor suppression chamber room and main steam line tunnel. Table 4.10-1 shows the parts of systems which compose the nuclear system process barrier and the room or areas in which differential temperature detection systems are installed to monitor various parts of systems. Temperature sensors are placed near the inlet and outlet ventilation ducts which provide normal ventilation. Additionally, temperature sensors are installed near the inlet and outlet of the standby coolers in the rooms where standby coolers are provided. (See table 4.10-1.) A differential temperature switch between each set of sensors initiates an alarm in the control room when the temperature difference reaches a point which indicates a leakage within the monitored room equal to the leakage rate limit. The instrument arrangement is illustrated on figures 4.10-1 and 4.10-2. The alarm point is determined analytically by calculating the increase in differential temperature which would result if a leak equal to the abnormal leakage rate occurred in the particular room. In the case of the RWC system equipment room, the temperature-sensing system provides an isolation signal to the RWC system at a high differential temperature.

B. Room Ambient Temperature

Temperature sensors are provided in the RCIC, HPCI, RHR, and RWC system equipment rooms, as well as in the main steam line tunnel and vapor suppression chamber room. (See figure 4.10-3.) The temperature switches associated with these sensors initiate an alarm at the ambient temperature rise for their particular area calculated to be indicative of the limiting leakage. Since temperatures outside the equipment room can affect the leakage detection accuracy of the absolute temperature alarm point, this detection system is considered as a secondary method of leakage detection. Remote readouts from temperature sensors are indicated in the control room. The room ambient temperature indication can be compared with the indications of each sensor in the differential temperature-sensing system to verify proper operation of the temperature sensors. A safety-related RTD/trip unit sensing system is provided in the RCIC, HPCI, RWC, and suppression chamber rooms. Signals from these RTDs and trip units provide isolation of the various systems.

C. Differential Flow Measurement (Cleanup System Only)

Due to the arrangement of the RWC system, differential flow measurement provides an accurate leakage detection method. As shown on figure 4.10-4, the flow from the reactor vessel is compared with the flow from the filter-demineralizer and the regenerative heat exchanger. An alarm in the control room and isolation signal are initiated when higher flow upstream from the filter-demineralizers indicates that a leak equal to the established leak rate limit may exist. This differential flow monitoring of the RWC system leakage is not required to mitigate a design basis event.

During periods of the RWC system restoration, maintenance, or testing, the RWC differential flow isolation instrumentation may be temporarily bypassed, thereby reducing the number of unnecessary isolations of the RWC system.

D. Leak Detection Sumps

Floor drain leak detection sumps are provided in areas where pumps and equipment designed to contain reactor coolant are located. These floor drain sumps are designed so that expected normal leakage can flow unimpeded through the floor drain. However, any increase in this leakage rate results in water collecting in the sump and the actuation of an alarm in the control room. A second drain release point, high enough in the sump so as not to prevent the alarm from sounding and of greater capacity, is provided to handle greater than expected leakage.

E. Visual and Audible Inspection

Inspections are made of all accessible areas periodically. The temperature and flow indicators discussed above are monitored regularly. Any indication of abnormal leakage can be investigated upon an instrument indication of such.

F. Reactor Building Sump Flow

The reactor building floor drainage system provides the most sensitive leak detection capability. Figure 4.10-5 shows a schematic diagram of this system. Water leakage into the torus compartment or equipment rooms will flow to one of the two reactor building sumps through the drainage system. Figures 4.10-6 and 4.10-7 show a schematic diagram of the sump pumps and compartment isolation capability which are used in the reactor building floor drain sumps.

Low leakage rates (~ 10 gal/min) are measured in instrument sumps shown on figure 4.10-8. Each sump contains a standpipe with four 1/2-in. holes spaced at 2-in. intervals above one another to provide a controlled rate of liquid buildup within the sump. Two level switches in the sump detect the height to which water has risen should significant leakage occur. The first alarm is placed on the lower level switch to give early indication of problems such as leakage or plugging of orifices. The second alarm is placed on the upper level switch to indicate a more significant situation requiring attention.

If the leakage is about 100 gal/min or if there is a failure of the sump pumps to work properly, all compartments will be isolated from each other by automatic valve closures. The valve closure signal alarms in the MCR. The floor drainage system provides excellent leak detection capability, since leak recognition becomes more rapid for higher leakage rates.

Once the compartments are isolated, the compartment receiving the leakage can be determined through the use of level switches (first signal locked in) located in the affected compartment. (All compartments have these instruments.) If significant leakage has been observed and it is downstream of the first valve, it can be stopped by closing that valve. The line which is leaking can be determined by selectively closing valves in the system's suction piping or by an operator entering the reactor building to determine the source of leakage. It should be noted that four level switches are located in the torus compartment, each near a low point in the floor, to aid in the location of leakage.

4.10.4 SAFETY EVALUATION

There are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier and in each area as shown in table 4.10-1. The instrumentation is designed so that it may be set to provide alarms at established leakage rate limits. The alarm points are determined analytically based on design data and on measurements of appropriate parameters made during startup and preoperational tests.

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier is threatened with significant compromise.

The limit on total leakage rate is established so that in the absence of normal ac power and feedwater, and without using the ECCS, the leakage loss from the nuclear system could be replaced. The CRD system furnished 45 gal/min and the RCIC system can furnish 400 gal/min to the reactor vessel, both of which are independent of feedwater and normal ac power. The limit on total leakage also allows a reasonable margin below the discharge capability of either the floor drain or equipment drain sump pumps. Thus, the established total leakage rate limit allows sufficient time for corrective action to be taken before either the nuclear system coolant makeup or the drywell sump removal capabilities are exceeded.

4.10.5 INSPECTION AND TESTING

The proper operation of the sensors and the logic associated with the LDS is verified for the proper operation during the LDS preoperational test and during inspection tests that is provided for the various components as they apply during plant operation.

The thermocouple sensors are checked against the known existing temperature. Failure of a thermocouple by open circuit between test periods is determined by the temperature switches which alarm an open circuit.

Each temperature switch, both ambient and differential types, are connected to dual thermocouple elements. Each temperature switch can be checked for operation by observing the ambient temperature or differential and then turning the trip point adjustment and determining that the switch operates at the proper temperature. Each temperature switch contains a trip light which lights when temperature exceeds the setpoint. The setpoint is manually reset to its required value by observing the setpoint on the meter. The RTD/trip unit assemblies associated with the LDS are part of the analog transmitter trip system. The inspection and testing requirements of these components are provided in section 7.18.

In addition, keylock test switches are provided so that logic can be tested without sending an isolation signal to the system involved. Therefore, a complete system check can be confirmed by checking activation of the isolation relay associated with each switch.

The primary containment sump drain monitoring system is tested by supplying makeup water to the sump at a sufficient flowrate to bring the water level above the sump high-level pump actuation point in less than predetermined time.

REFERENCES

1. "Reactor Primary Coolant System Rupture Study," Quarterly Progress Report No. 11, Appendix A, GEAP-5587, October-December 1967.

2. Reynolds, M.B., "Failure Behavior in ASTM A106B Pipes Containing Axial Through Wall Flows," GEAP-5620, April 1968.

3. Duffy, A. R., Eiber, R. J. and Maxey, W. A., "Recent Work on Flow Behavior in Pressure Vessels," April 1969.

4. Moody, F. J., "Maximum Two-Phase Vessel Blowdown from Pipes," APED-4827, April 1965.

5. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

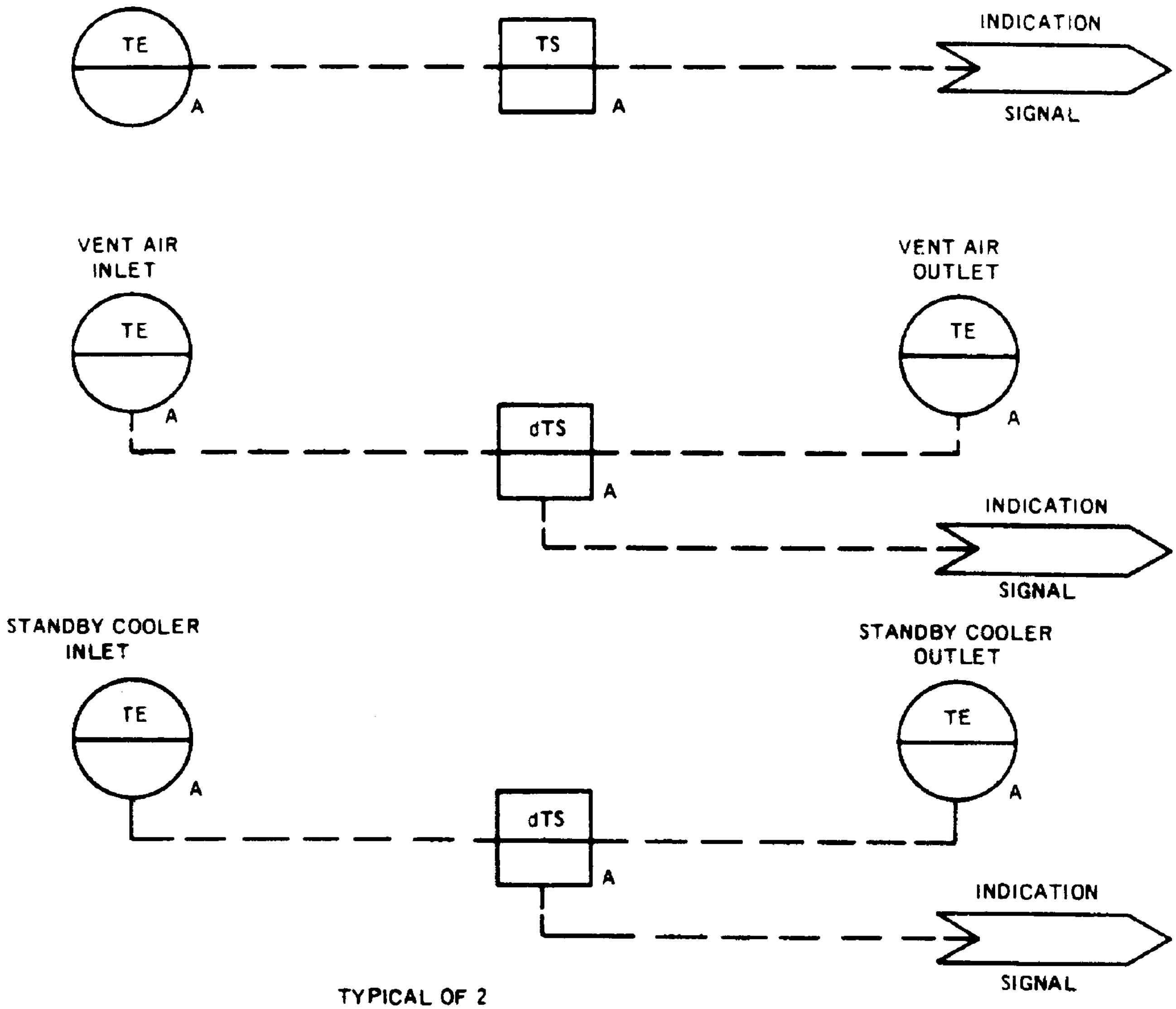
TABLE 4.10-1

SUMMARY OF ISOLATION/ALARM OF SYSTEMS MONITORED AND THE LEAK DETECTION METHODS USED

		Variable Monitored													
Function		A	A	A	A	A/I	A	A/I	A/I	A	A/I	A/I	I	I	A
Source of Leakage	Location	PC high temperature	PC sump high flowrate	PC air cooler PSW ΔT (high)	Equipment area T and ΔT (high)	Low steam line pressure	RB sump high flowrate	Equipment area temp high	Suppression pool area T and ΔT (high) time delay	PC pressure (high)	High flowrate	High turbine exhaust pressure	CU flow (high differential)	RPV water levels 1, 2, or 3	Fission products high radiation
Main steam line	PC	X	X	X		X[b]				X				X	X
	RB				X[a]	X[b]	X				X[b]			X	
RHR	PC	X	X	X						X					X
	RB				X		X								
RCIC or HPCI steam	PC	X	X	X						X					X
	RB				X	X	X	X	X		X[b]	X			
RCIC or HPCI water	PC														
	RB						X								
Cleanup water	PC	X	X	X						X			X	X	X
(hot)	RB				X		X	X					X	X	
(cold)	RB						X						X	X	
Feedwater	PC	X	X	X						X					X
	RB						X								

LEGEND
PC - primary containment
RB - reactor building
CU - cleanup
A - alarm
I - isolation
T - temperature
RPV - reactor pressure vessel

a. Isolate on high ambient temperature in main steam tunnel.
b. Break downstream of flow element will isolate the steam line.



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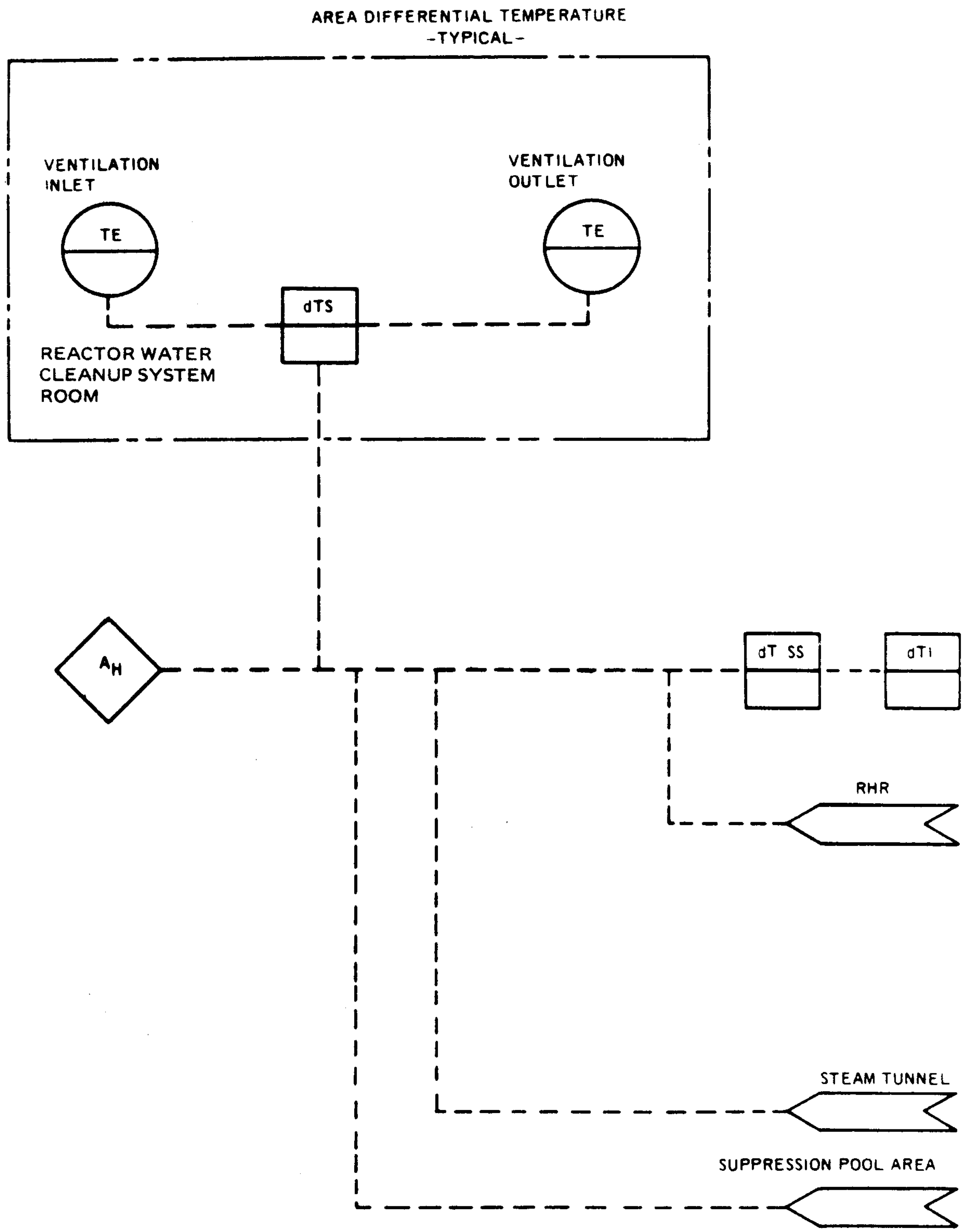
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

TYPICAL TEMPERATURE MONITORING
LEAK DETECTION SYSTEM

FIGURE 4.10-1

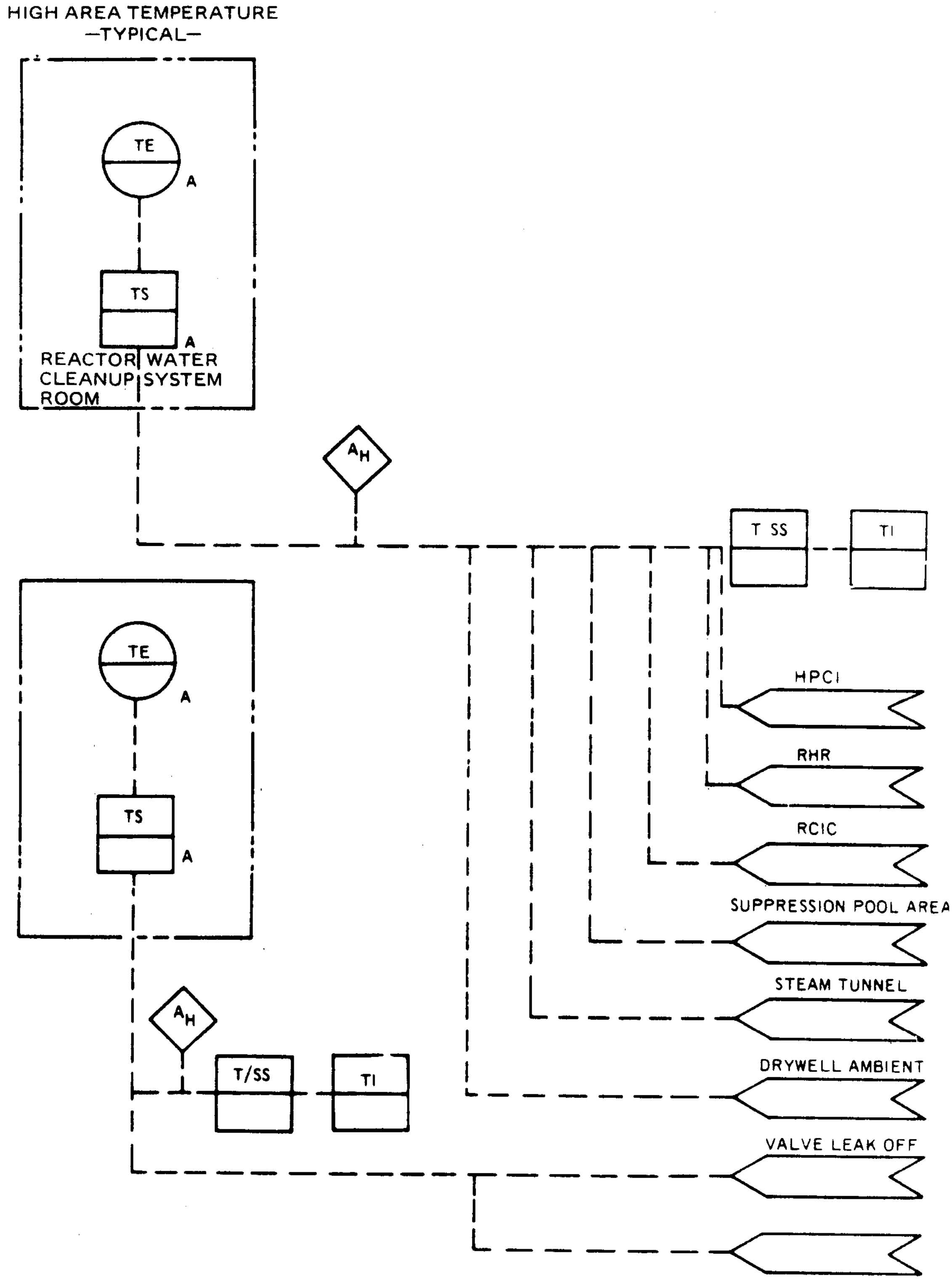


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

LEAK DETECTION
DIFFERENTIAL TEMPERATURE
INDICATION SCHEMATIC

FIGURE 4.10-2

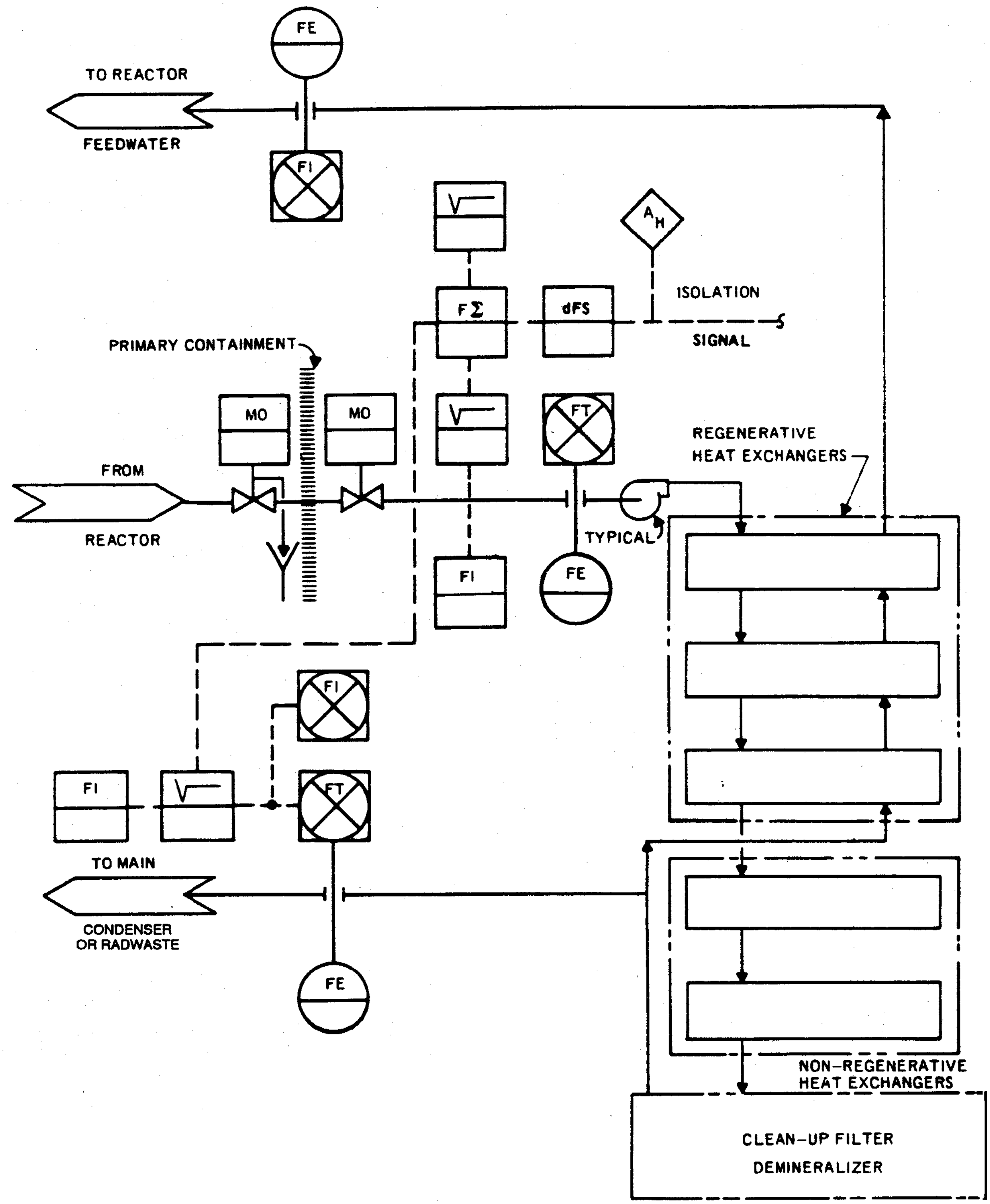


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

LEAK DETECTION
ABSOLUTE TEMPERATURE
INDICATION SCHEMATIC

FIGURE 4.10-3



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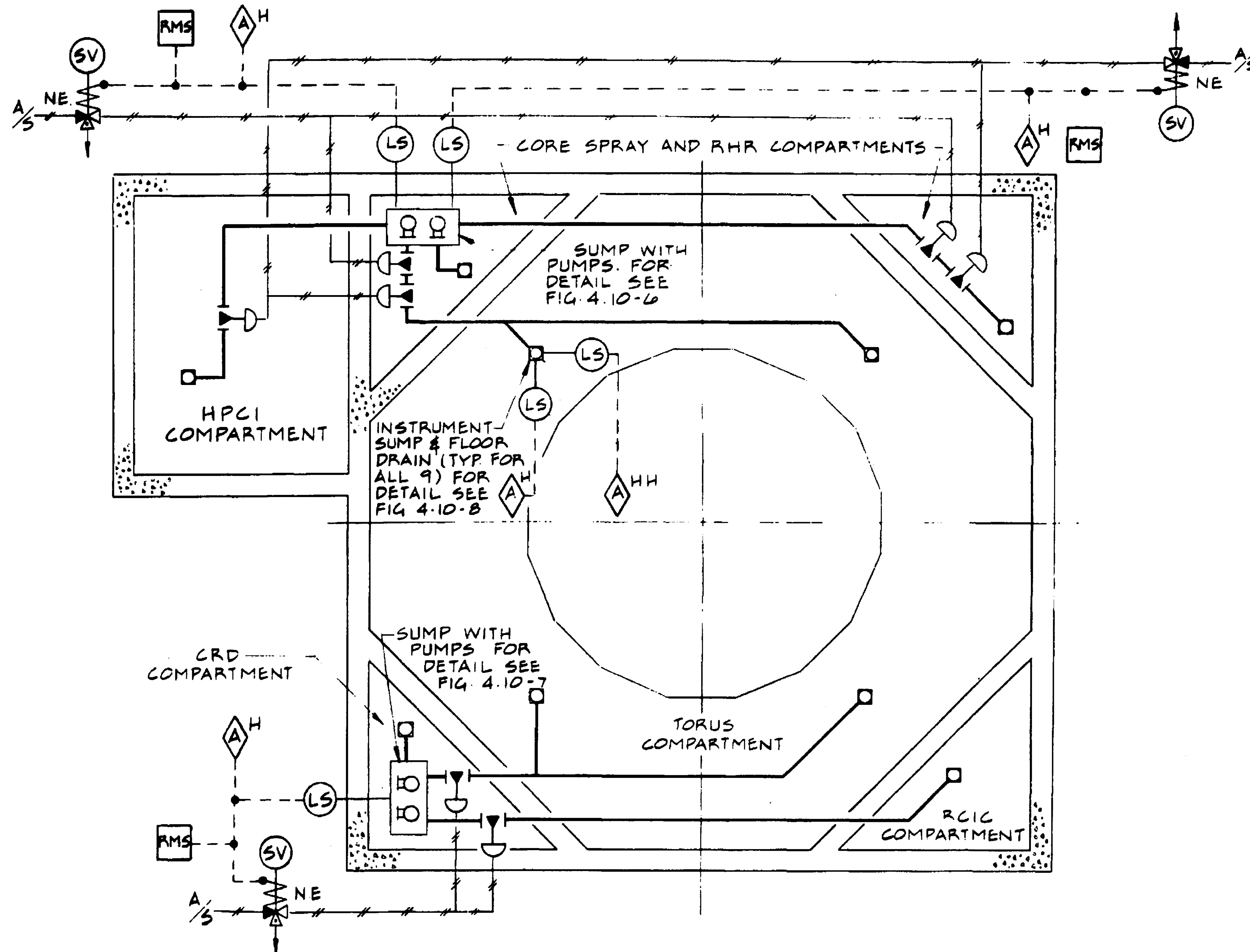
LEAK DETECTION
REACTOR WATER CLEANUP
DIFFERENTIAL FLOW

FIGURE 4.10-4



ACAD 1041005

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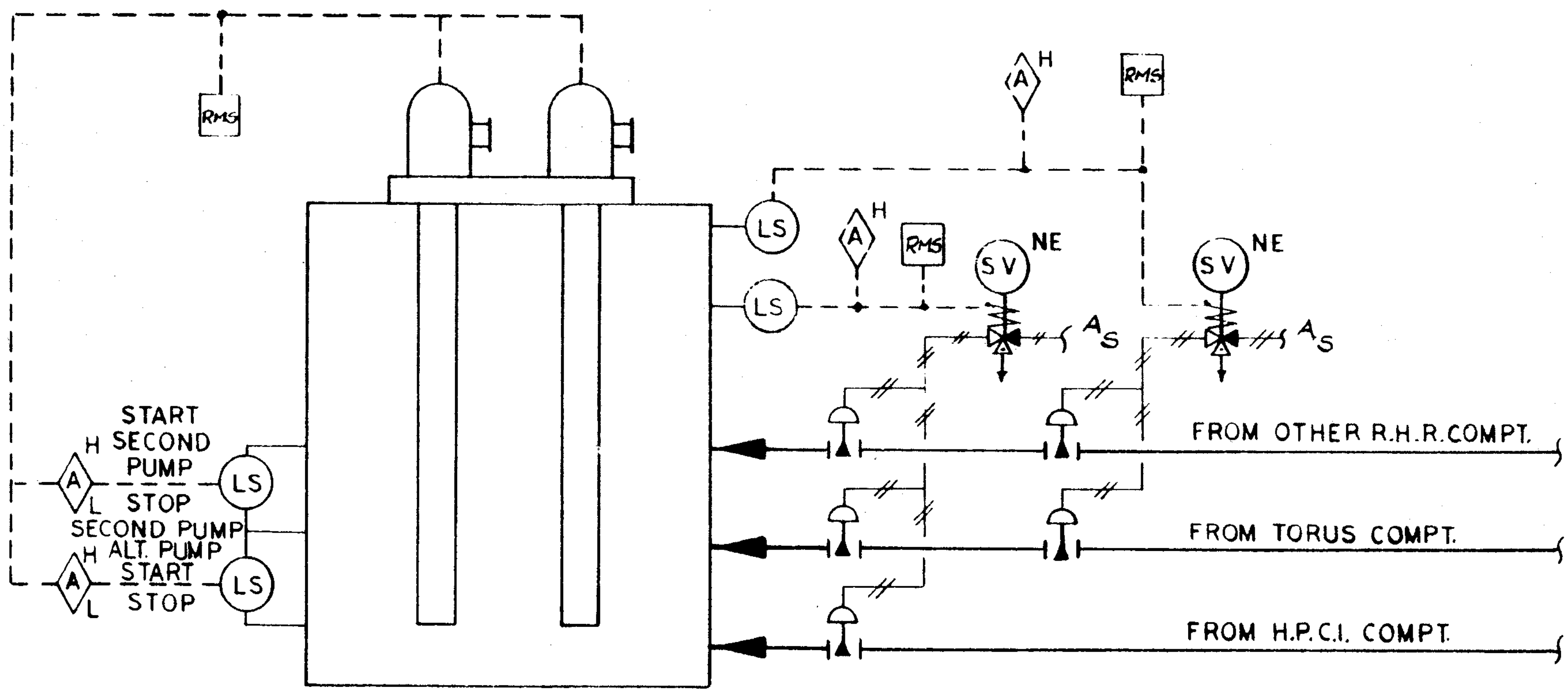
RRS QUALITY GROUP
SCHEMATIC DIGRAM

FIGURE 4.10-5



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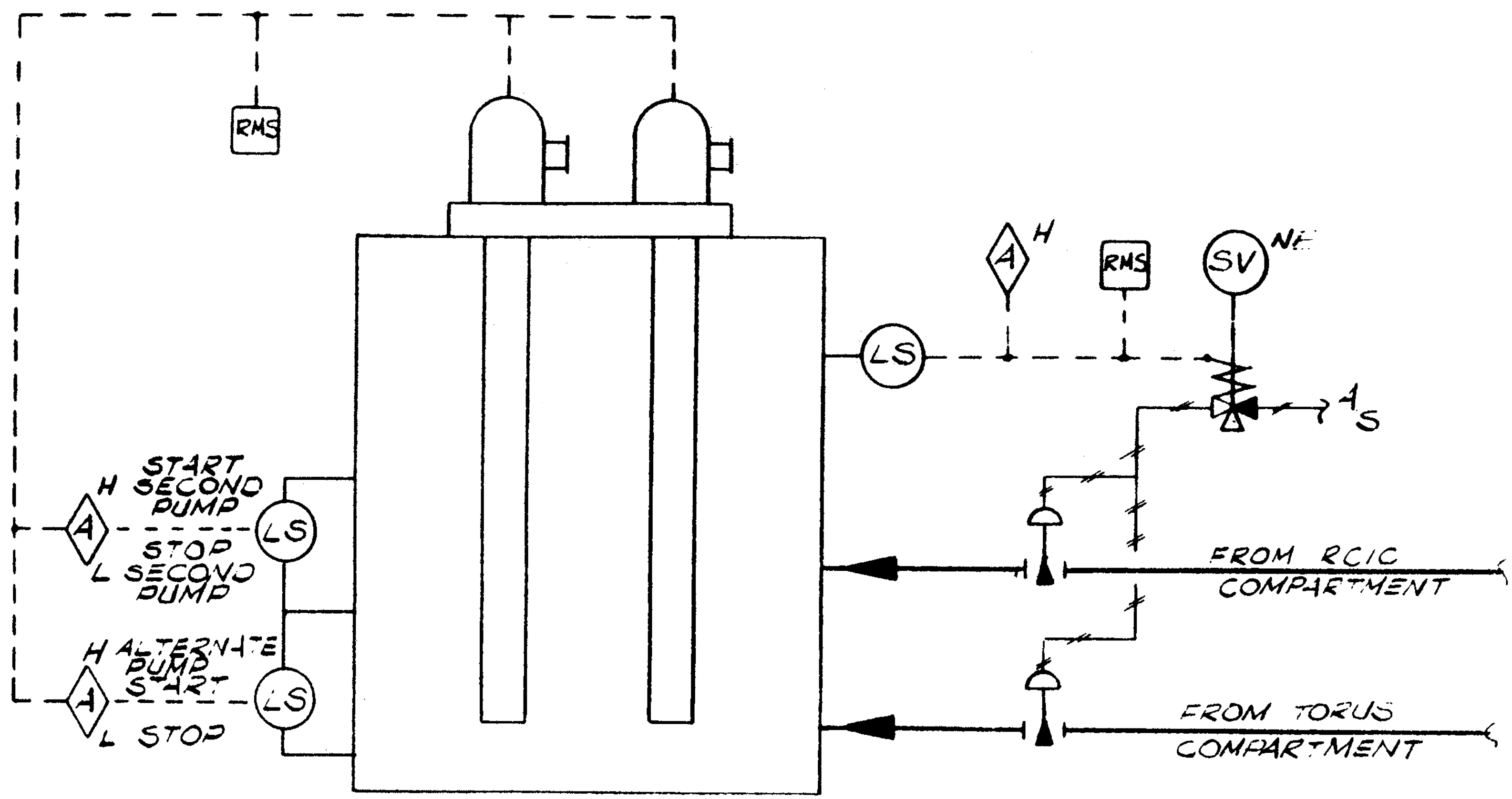
UNIT 1

SCHEMATIC DIAGRAM RHR COMPARTMENT
FLOOR DRAIN SUMP WITH ISOLATION CAPABILITY

FIGURE 4.10-6



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EDWIN I. HATCH NUCLEAR PLANT
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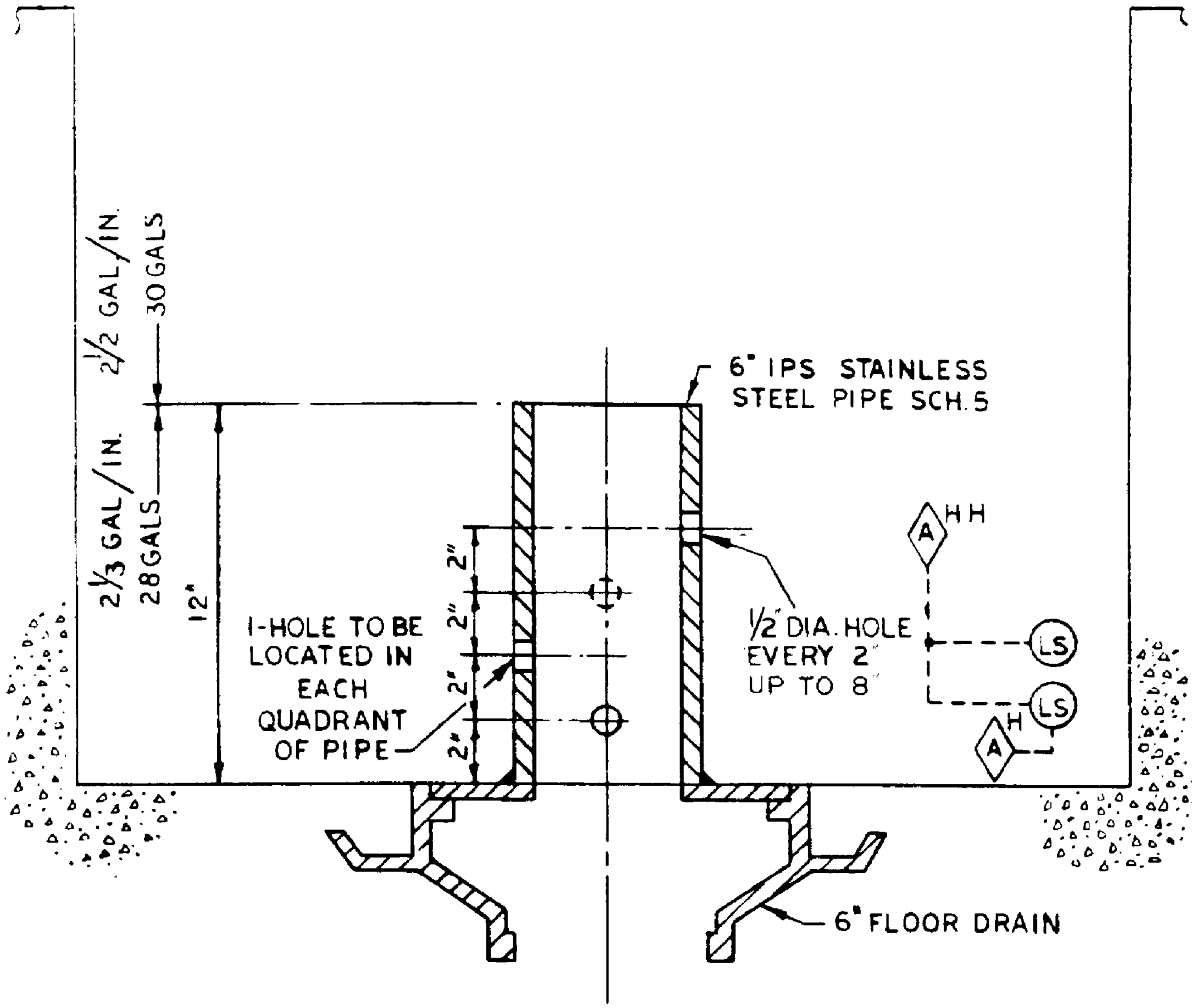
SCHEMATIC DIAGRAM CRD COMPARTMENT FLOOR DRAIN SUMP WITH ISOLATION CAPABILITY

FIGURE 4.10-7



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COMPARTMENT INSTRUMENT SUMP

FIGURE 4.10-8

4.11 LOW-LOW SET RELIEF LOGIC SYSTEM

The current safety analysis report[5] and reactor operating pressure increase (ROPI) project report[6] demonstrate that for HNP-1, the low-low set relief logic system analytical limits remain unchanged at a power level of 2804 MWt and a reactor vessel pressure of 1060 psia.

4.11.1 DESIGN BASES

The low-low set (LLS) relief logic system is designed to:

- Mitigate the effects of postulated thrust loads on the safety relief valve (SRV) discharge lines (SRVDLs) and the effects of postulated high-frequency pressure loads on the torus shell caused by subsequent actuations of the SRVs during a small- or intermediate-break loss-of-coolant accident (LOCA).
- Extend the time between SRV subsequent actuations to allow the SRVDL water leg to return to original level after an actuation.
- Remain operable in event of loss-of-offsite power (LOSP).
- Perform its design function assuming the worst postulated single failure.
- Assure that no single failure shall cause more than one LLS valve to stick open.
- Be testable during normal plant operation.

4.11.2 SYSTEM DESCRIPTION

The arrangement of the SRV systems with the LLS design for HNP-1 is shown in table 4.11-1. The LLS design involves four non-automatic depressurization system (ADS) SRVs. The LLS control logic operates the four valves through arming and actuation. The arming function requires concurrent signals of any SRV opening and a high reactor vessel pressure exceeding scram setpoint.

The LLS system consists of SRV open-close monitors, nuclear boiler pressure instrumentation, and a cabinet housing LLS logic relays, solenoid valves, and pneumatic supply. (Accumulators are part of the pneumatic supply.) The SRV open-close monitors are pressure switches. Redundant switches on each tailpipe indicate an SRV opening. The nuclear boiler pressure instrumentation provides pressure trips for the arming pressure permissive and the LLS setpoints. One transmitter and master trip unit provide the arming permissive trip. A slave trip unit and another transmitter/master trip unit provide the two-out-of-two logic for LLS opening and one-out-of-two logic for reclosing logic to the solenoid valves. This instrumentation is part of the analog transmitter trip system which is discussed in section 7.18. The solenoid valves and the drywell pneumatic system are used to pneumatically operate the LLS valves. An automatic opening of SRVs will also occur at setpoints distributed among 3 groups (table 4.11-1) by pressure switch relay contacts inserted into the LLS pilot solenoid valve circuit. (See subsection 4.4.5.) The LLS valves discharge into the suppression pool.

4.11.3 SAFETY EVALUATION

The objective of this analysis is to demonstrate that the design is capable of mitigating the thrust loads on the SRVDLs and the high-frequency loads on the torus shell from subsequent SRV actuations during small- and intermediate-break LOCAs. This can be accomplished by extending the time between actuations to exceed the water leg clearing time and by limiting subsequent SRV actuations to LLS valves only. The LLS system precludes the untimely actuation of the ADS valves by controlling only the LLS valves.(2) The capability of allowing sufficient time between SRV actuations was demonstrated by an analysis.(2) The overall response of the reactor pressure vessel (RPV) and, specifically, the response of the SRV system during actuations were evaluated using current boiling water reactor (BWR) evaluation methods and assumptions which are in conformance with the plant design basis.

The logic is designed to initiate opening of the four LLS valves within 1 s of an SRV opening (when reactor pressure is greater than high pressure scram setpoint) to prevent reopening of the SRV.

The limiting events, which would cause the shortest time between SRV actuations, were analyzed to demonstrate the capability of LLS to extend the time between SRV actuations, thus assuring the water leg will recede to original level. These events are:

- Small break with early isolation due to LOSP.

- Small break with early isolation due to LOSP and a single failure.

Assuming the worst-case single failure, the LLS logic in HNP-1 can extend the time between SRV actuations from less than 3 s to 39 s. Therefore, the LLS can mitigate the thrust load and shell pressure load concern from subsequent SRV actuation during a small-break LOCA even with the worst-case single failure and early reactor isolation occurring concurrently.

The predicted system responses for the limiting events postulated for HNP-1 are shown in figures 4.11-1 and 4.11-2, which show that the system pressure increases sharply as soon as isolation is completed. The pressure rise causes all 11 SRVs to actuate and initiates LLS. Actuation of SRVs quickly depressurizes the reactor vessel and all non-LLS valves will close at the respective pilot setpoints or at their mechanical backup electric trip unit's deadband minimum. (See subsection 4.4.5.) The LLS valves remain open until their LLS closing setpoints are reached. When the lowest LLS valve closes, the reactor pressure rises again and only that valve continues to cycle to control reactor pressure. The time between actuations is ~ 36 s for HNP-1. Figure 4.11-2 demonstrates the case in which two LLS valves become inoperative in the lowered setpoint relief mode. The remaining two LLS valves can turn the system pressure around before any non-LLS valves actuate at the pilot setpoints; thereafter, the lower operable LLS valve cycles to control reactor pressure. The time between actuations is ~ 39 s. The time is longer, because the two LLS valves take a longer time to depressurize the reactor and subsequent repressurization by decay heat is at a slower rate.

With or without the LLS logic, the high-pressure coolant injection (HPCI) system or the reactor core isolation cooling (RCIC) system provide adequate core cooling.[2] Although the steam loss per discharge is higher than the LLS valves, the integrated total steam losses are identical for a LLS valve and a non-LLS valve. Initiation of HPCI or RCIC compensates for the steam loss through the LLS valves and provides adequate core cooling.

The LLS design does not result in any unacceptable safety concerns for any anticipated operational occurrences or accidents identified in HNP-2-FSAR chapter 15, Safety Analysis.[1][2] Although the scenario for some events, such as loss-of-feedwater flow and small-break LOCA, may be changed, the safety margin of the plant is not reduced.

4.11.4 TESTS AND INSPECTIONS

The LLS relief logic system can be demonstrated to be operable at regularly scheduled intervals by performance of:

- Channel functional tests, including calibration of the pressure trip units.
- Channel calibration of all transmitters.
- Functional testing of pressure switches.
- Logic system functional tests including simulated automated operation of the entire system.
- Response time testing.

In addition, each master trip unit provides continuous readout of the transmitter control current via the meter on its front, which is calibrated in terms of process variable. Therefore, the operator is able to cross-check the transmitter output currents by comparison and determine whether one of the transmitters is malfunctioning.

REFERENCES

1. "Low Low Set Logic and Lower MSIV Water Level Trip for BWRs with Mark 1 Containment," NEDE-22223, General Electric Company, September 1982.

2. "Low Low Set Relief Logic System and Lower Water Level Trip for Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22224, General Electric Company, December 1982.

3. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDC-32749P, General Electric Company, July 1997.

4. "Safety Review for Edwin I. Hatch Nuclear Power Plant Units 1 and 2 Updated Safety/Relief Valve Performance Requirements," NEDC-32014P, General Electric Company, April 1996.

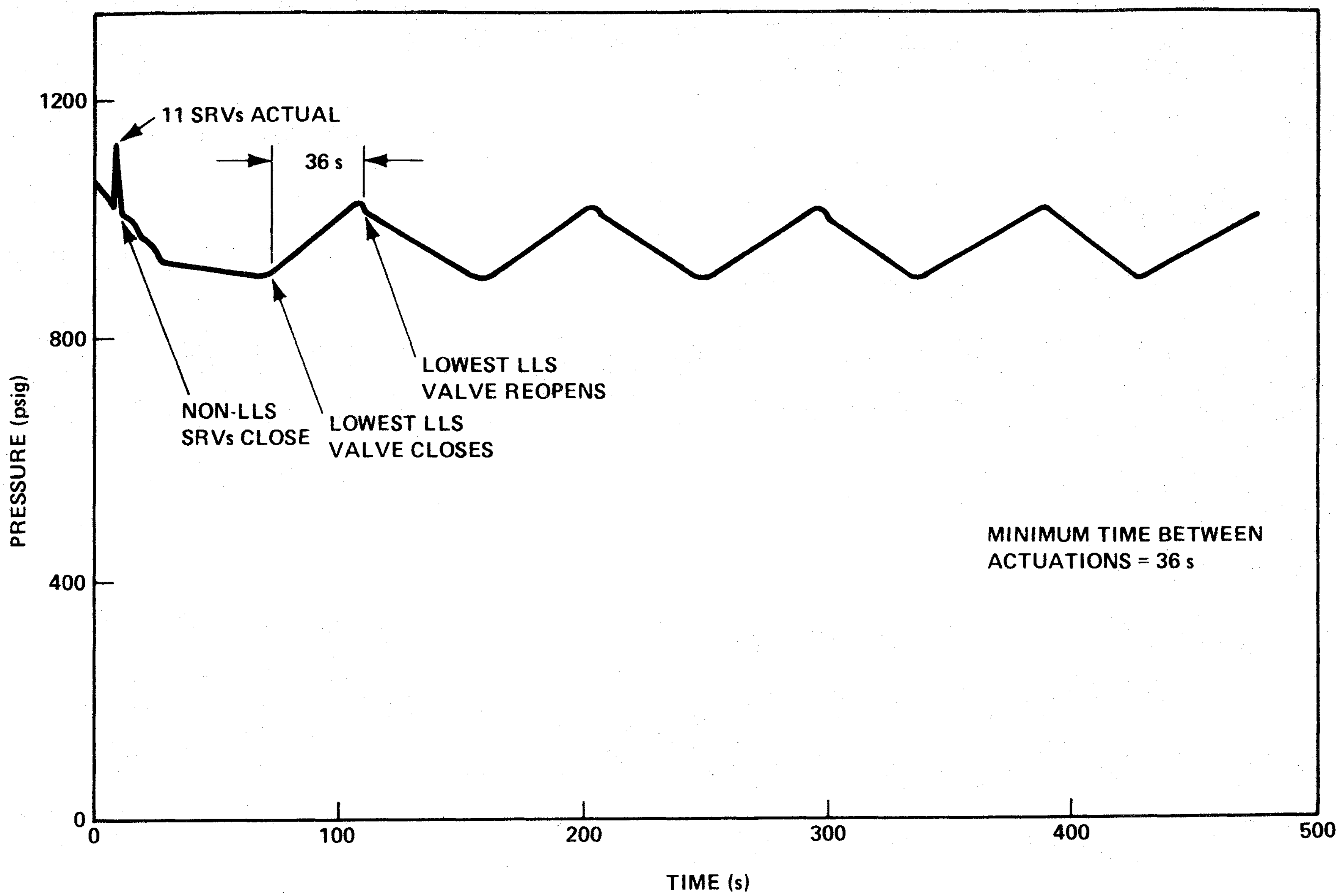
5. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

6. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2, GE-NE-0000-0003-0634-01, Revision 1,” GE Nuclear Energy, July 2003.

TABLE 4.11-1

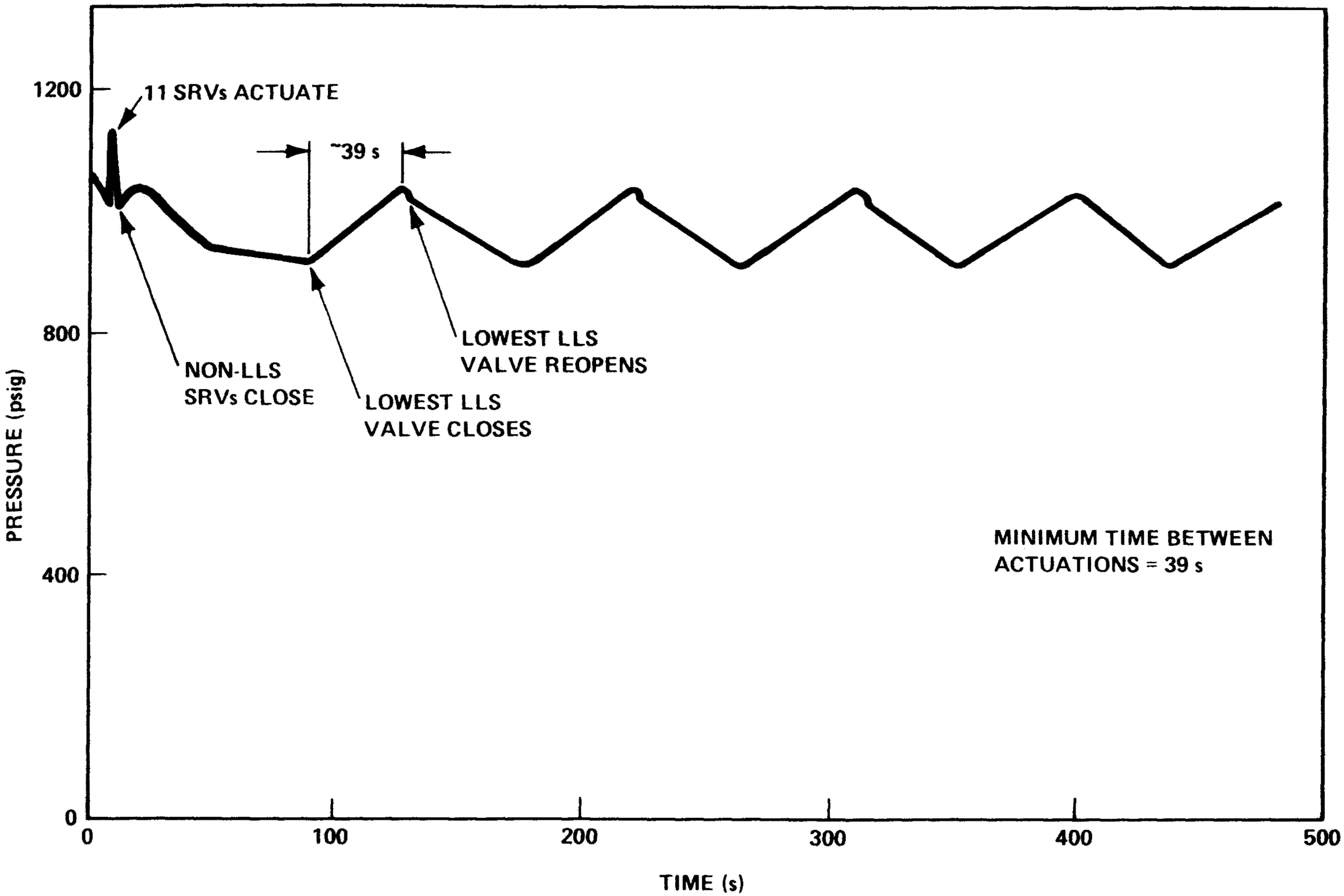
LOW-LOW SET SRV SYSTEM FOR HNP-1

	SRVs										
	A	B	C	D	E	F	G	H	J	K	L
Pressure relief function	X	X	X	X	X	X	X	X	X	X	X
ADS function	-	X	-	X	X	X	-	-	X	X	X
LLS relief logic channel	B	-	D	-	-	-	C	A	-	-	-
Valve group	I	III	I	II	III	II	I	I	III	II	II
Steam pilot mechanical opening setpoint (psig)	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Electrical backup to mechanical opening setpoint (psig)	1120	1140	1120	1130	1140	1130	1120	1120	1140	1130	1130
LLS opening allowable value	≤ 1020		≤ 1045				≤ 1035	≤ 1005		-	-
LLS closing allowable value	≤ 872		≤ 897				≤ 887	≤ 857		-	-



REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	HNP-1 SYSTEM RESPONSE FOR LIMITING EVENT WITH FOUR-VALVE LLS
	FIGURE 4.11-1



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SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

HNP-1 SYSTEM RESPONSE FOR LIMITING EVENT WITH SINGLE FAILURE (ONLY TWO LLS VLAVES OPERABLE)

FIGURE 4.11-2

5.0 CONTAINMENT SYSTEMS

5.1 SUMMARY DESCRIPTION

5.1.1 GENERAL

The containment systems are designed to prevent the spread of radiation by utilizing the "multibarrier" concept that consists of two containment systems.

A. The primary containment system is a pressure-suppression system that forms the first barrier.

B. The secondary containment system that forms the second barrier contains the primary containment system and other nuclear systems, and minimizes the ground-level release of airborne radioactive material.

5.1.2 PRIMARY CONTAINMENT SYSTEM

The primary containment system houses the reactor pressure vessel, the reactor coolant recirculation system, and other branch connections of the reactor coolant system (RCS). The primary containment consists of the drywell, the suppression chamber that stores a large volume of water, a connecting vent system between the drywell and suppression chamber, isolation valves, a vacuum relief system, containment cooling systems, and other service equipment.

The drywell is a steel pressure vessel in the shape of a light bulb, and the suppression chamber is a torus-shaped steel pressure vessel located below and encircling the drywell.

The primary containment system is designed to withstand the pressures resulting from a breach of the nuclear system process piping up to and including an instantaneous circumferential break of the reactor recirculation piping. The primary containment system provides a holdup for the decay of any released radioactive material and stores sufficient water to:

- Condense the steam released as a result of a breach in the nuclear system process barrier.
- Supply the emergency core cooling system.

5.1.3 SECONDARY CONTAINMENT SYSTEM

The secondary containment system encloses the following:

- Primary containment system.

- Refueling and reactor servicing areas.
- New and wet spent-fuel storage facilities.
- Other reactor auxiliary systems.

The secondary containment system serves as the primary containment during reactor refueling and maintenance operations when the primary containment is open, and as an additional barrier when the primary containment system is functional. The secondary containment system consists of the reactor building, the standby gas treatment system, and the main stack.

The secondary containment system is designed to:

- Withstand the maximum postulated seismic event.
- Provide holdup, treatment, and an elevated release point for any fission products released to it.
- Protect all systems (located within the reactor building) required for the safe shut down of the plant from all postulated environmental events, including tornadoes.

5.2 PRIMARY CONTAINMENT SYSTEM

The current safety analysis report[6], reactor operating pressure increase (ROPI) project report[7], and the GNF3 new fuel introduction containment analyses report[8] demonstrate that the HNP-1 primary containment systems can safely operate at a power level of 2804 MWt and 1060 psia.

5.2.1 SAFETY DESIGN BASES

The primary containment system is designed to:

A. Withstand the peak transient pressures that can occur due to the postulated design basis loss-of-coolant accident (LOCA); i.e., a mechanical failure of the reactor primary system equivalent to the circumferential rupture of one of the reactor coolant recirculation system pipes.

B. Be consistent with the performance objectives of the emergency core cooling system (ECCS) relative to metal-water reactions and other chemical reactions subsequent to the postulated design basis LOCA.

C. Indefinitely maintain the functional integrity of the primary containment after the postulated design basis LOCA.

D. Permit filling the primary containment system drywell with water above the reactor core.

E. Protect the primary containment system against missiles from internal or external sources and excessive motion of pipes that can directly or indirectly endanger the integrity of the containment.

F. Withstand jet forces associated with the flow from the postulated rupture of any pipe within the containment.

G. Limit leakage during and following the postulated design basis accident (DBA) to values that are substantially less than leakage rates resulting in doses approaching the reference doses in 10 CFR 50.67.

H. Permit leakage testing to confirm the integrity of the containment at the peak transient pressure resulting from the postulated DBA.

I. Rapidly condense the steam portion of the flow from the postulated DBA rupture of a recirculation line so that the peak transient pressure is substantially less than the containment design pressure.

J. Conduct the flow from postulated pipe ruptures to the suppression pool; distribute such flow uniformly throughout the pool, and limit the ΔP between the drywell and the suppression pool during the various post-accident cooling modes.

K. Rapidly close or isolate all pipes or ducts penetrating the primary containment by providing a containment barrier in the subject pipes or ducts, as required, to maintain leakage within permissible limits.

The safety design bases documented in the Mark I Containment Long-Term Program Safety Evaluation Report, NUREG-0661,[(1)] are included in supplement KA.

5.2.1.1 Containment Design Criteria Against Buckling

The containment is designed for concentrated loads, thermal loads, and seismic loads accompanying internal pressure loads. The design stress calculations considered stresses due to these loads and their effect on the overall stability of the containment vessels. Section K.6 provides a summary of the design criteria against buckling.

5.2.2 DESCRIPTION

5.2.2.1 General

The design employs a low-leakage pressure-suppression containment system that houses the reactor pressure vessel (RPV), the reactor coolant recirculation loops, and other branch connections of the reactor primary system. The pressure-suppression system consists of the following:

- Drywell.
- Suppression chamber (torus) that stores a large volume of water.
- Connecting vent system between the drywell and the suppression pool.
- Isolation valves.
- Vacuum relief system.
- Containment cooling systems.
- Other service equipment.

The primary containment system design parameters are provided in table 5.2-7.

The primary containment system free volume is filled with a nitrogen atmosphere during normal operation. The containment atmospheric control system is capable of reducing and maintaining the oxygen content of the atmosphere below 4% during normal operation.

In the event of a process system piping failure within the drywell, reactor water and steam are released into the drywell gas space. The resulting increased drywell pressure forces a mixture of air, steam, and water through the vent system into the suppression pool. The steam condenses rapidly in the suppression pool, resulting in rapid pressure reduction in the drywell. Air transferred during reactor blowdown to the suppression chamber pressurizes the chamber and is subsequently vented to the drywell through the vacuum relief system as the pressure in the drywell drops below that in the suppression chamber. Cooling systems remove heat from the drywell and the suppression pool for continuous cooling of the primary containment under the postulated DBA conditions. Isolation valves ensure the containment of radioactive material within the primary containment that might be released from the reactor to the containment during the course of an accident. Other service equipment maintains the containment within its design parameters during normal operation. The primary containment system design loading considerations are provided in chapter 12 and appendix K. The safety analysis presented in HNP-2-FSAR chapter 15 demonstrates the effectiveness of the primary containment system as a radiological barrier. In addition, primary containment pressure and temperature transients from postulated DBAs are also discussed in HNP-2-FSAR chapter 15.

5.2.2.2 Drywell

The drywell is a steel pressure vessel with a spherical lower portion 65 ft in diameter and a cylindrical upper portion 35 ft 7 in. in diameter. The overall height of the drywell is ~ 111 ft. The design, fabrication, inspection, and testing of the drywell comply with the requirements of the ASME Code, Section III, Subsection B, Requirements for Class B Vessels, which pertains to containment vessels for nuclear power stations. The primary containment is fabricated of SA-516 grade 70 plates.

The drywell is designed for an internal pressure of 56 psig coincident with a temperature of 281°F, with applicable dead, live, and seismic loads imposed on the shell. Thermal stresses in the steel shell due to temperature gradients are also incorporated into the design. Thus, in accordance with the ASME Code, Section III, the maximum drywell pressure is 62 psig.

Although not required by the ASME Code, special precautions were taken in the fabrication of the steel drywell shell. Charpy V-notch specimens were used for impact testing of plate and forging material to verify proper material properties. Plates, forgings, and pipe associated with the drywell have an initial nil ductility transition temperature (NDTT) ≤ 0°F when tested in accordance with the appropriate code for the materials. The drywell is assumed to be neither pressurized nor subjected to substantial stress at temperatures below 30°F.

The drywell is enclosed in a reinforced concrete structure for shielding purposes. Resistance to deformation and buckling of the drywell plate is provided in areas where the concrete backs up the steel shell. Above the transition zone, the drywell is separated from the reinforced concrete by a gap of ~ 2 in. Shielding over the top of the drywell is provided by removable, segmented, reinforced concrete shield plugs.

The removable shield plugs consist of six 3-ft-thick reinforced concrete segments spanning up to 38 ft in two separate layers of 3 segments, each weighing 160 kips. The plug segments are designed for 1000 lb/ft^2 uniform floor loading and were checked for the effects of the tornado missile and a heavy load drop. The most likely dropped object is one of the various floor hatch covers weighing 7 to 9 kips each. The analysis was made for a 10-kip hatch cover falling 24 ft and a wooden plank tornado missile having a velocity of 300 mph.(2)

For the worst case (the hatch cover drop), the analysis indicated elastic response with rebar tension, and bond and shear stresses equal to 0.8, 0.2, and 0.65 times, respectively, the ultimate stress values given in American Concrete Institute (ACI) 318-63. The plug sides and bottom surfaces are lined with stainless steel that, although not credited in the analysis, provides even more safety margin against collapse or spalling. Also, the lifting devices are designed with a safety factor of 5 based upon ultimate stress.

The methods for determining steam or reactor coolant leaks are discussed in paragraph 4.10.3.4.1.

In addition to the drywell head, one double-door airlock and two bolted equipment hatches provide access into the drywell.

5.2.2.3 Suppression Chamber and Vent System

5.2.2.3.1 General

The suppression chamber, the vent system, and the drywell are designed, fabricated, and tested in accordance with ASME Code, Section III, for Class B vessels.

The suppression pool, which is contained within the suppression chamber, initially serves as the heat sink for any postulated anticipated operational occurrence (AOO) or accident condition in which the normal heat sink (main condenser or shutdown cooling system) is unavailable. Energy is transferred to the suppression pool by either the discharge piping from the safety relief valves (SRVs) or the drywell vent system. The SRV discharge piping is used as the energy transfer path for any condition requiring the operation of the relief valves. The drywell vent system is the energy transfer path for all energy releases to the drywell.

The instantaneous circumferential rupture of the reactor coolant recirculation piping represents the most rapid energy addition to the pool for all postulated AOO and accident conditions. For this accident, the vent system connecting the drywell and suppression chamber conducts flow from the drywell to the suppression chamber without excessive resistance and distributes this flow effectively and uniformly in the suppression pool. The suppression pool receives this flow, condenses the steam portion of the flow, and releases the noncondensible gases and any fission products to the suppression chamber air space.

5.2.2.3.2 Suppression Chamber

The suppression chamber is a steel pressure vessel in the shape of a torus located below and encircling the drywell, with a major diameter of ~ 107 ft and a cross-sectional diameter of ~ 28 ft. The suppression chamber contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside the chamber for inspection.

The torus-shaped suppression chamber is designed to the same material and code requirements as the steel drywell vessel. The material has an NDTT ≤ 0°F.

Modifications made to the suppression chamber due to hydrodynamic loads identified during the Mark I Containment Long-Term Program are presented in supplement KA.

5.2.2.3.3 Vent System

Large vent pipes connect the drywell and the suppression chamber. Eight circular vent pipes, each having a diameter of 5 ft 11 in., are provided. The vent pipes are designed for the same pressure and temperature conditions as the drywell and suppression chamber. Jet deflectors in the drywell at the entrance of each vent pipe prevent possible damage to the vent pipe from jet forces that can accompany a pipe break within the drywell.

The vent pipes are fabricated of SA-516 grade 70 steel and comply with requirements of the ASME Code, Section III, Subsection B. The vent pipes are provided with expansion joints enclosed within sleeves to accommodate differential motion between the drywell and suppression chamber. The vent pipe bellows are designed, fabricated, and tested in accordance with the ASME Code, Section III, Class B, and the Code Cases 1330-1 and 1177-5. The membrane stresses are within the code allowable stresses. Paragraph K.4.4 addresses the protection from jet forces.

Modifications made to the vent system due to hydrodynamic loads identified during the Mark I Containment Long-Term Program are presented in supplement KA.

The drywell vents are connected to a 4-ft 6-in.-diameter vent header from the torus that is contained within the suppression chamber airspace. Projecting downward from the header are 80 downcomer pipes that are 24 in. in diameter and terminate 4 ft 0 in. below the water surface of the suppression pool.

The vent system inside the torus is not pressure tested, although the vent pipes from the drywell to the suppression chamber are tested as part of the primary containment test. The vent system, which is designed for a ΔP of 56 psi between the drywell and suppression chamber, would be subjected to $<$ 35 psid during a LOCA.

The adequacy of the downcomer design for the suppression containment is ensured by limiting the values of the various design parameters (including submergence) to the range of values tested at Moss Landing.(3) Downcomer submergences between 12 ft 5 in. and minus 2 ft all demonstrate complete condensation of the blowdown steam. The Bodega Bay series of tests(4) had a 24-in.-diameter downcomer that is the same as the HNP-1 containment. For the test series, downcomer submergence was varied from 5 ft to 3 ft, with complete condensation occurring in all tests.

Thus, it can be concluded that the vent pipe submergence of 3 ft 8 1/2 in., corresponding to the minimum suppression pool water level required by the Technical Specifications, meets the criterion for the tested range. Therefore, in the event of a LOCA, complete condensation of blowdown steam will occur.

5.2.2.3.4 Suppression Pool

The suppression pool contains demineralized water; serves as a heat sink for postulated AOOs, accidents, and special events; and is a source of water for the ECCS.

The suppression pool receives energy in the form of steam and water from either the SRV discharge piping or the drywell vent system downcomers that discharge under water. The steam is condensed in the suppression pool. The condensed steam and any water carryover cause an increase in pool volume and temperature. Energy is removed from the suppression pool when the residual heat removal (RHR) system is operating in the suppression pool cooling mode.

The SRV discharge lines extend to the deepest part of the suppression pool where they have a minimum submergence of ~ 8 ft. Each line terminates in a tee, eliminating unbalanced thrust forces on the pipe, and pipe supports and anchors. The tee is located ~ 4 ft from the bottom of the torus and oriented such that the discharged water and steam do not directly impinge upon the torus shell or other structures.

The suppression pool is the primary source of water for the core spray (CS) system and the low-pressure coolant injection (LPCI) mode of the RHR system, and the secondary source of water for the reactor core isolation cooling (RCIC) and the high-pressure coolant injection (HPCI) systems. Suppression pool water level and temperature are continuously monitored in the main control room (MCR).

5.2.2.4 <u>Penetrations</u>

5.2.2.4.1 General

Containment penetrations are designed for the same pressure and temperature conditions as the drywell and suppression chamber, and have the capability to:

A. Withstand the forces caused by impingement of the fluid from the rupture of the largest local pipe or connection without failure.

B. Accommodate the thermal and mechanical stresses that may be encountered during all modes of operation without failure.

C. Withstand the maximum reaction that the pipe to which they are attached is capable of exerting.

The penetrations are listed in ***Technical Requirements Manual (TRM) table T7.0-1 (incorporated by reference into the FSAR)***. Load combinations and allowable stresses are described in chapter 12.

5.2.2.4.2 Pipe Penetrations

Two general types of pipe penetrations are provided:

- Penetrations that must accommodate thermal movement as shown in figure 5.2-1.
- Penetrations that experience relatively little thermal stress as shown in figures 5.2-2 and 5.2-3.

Figure 5.2-4 shows a typical instrument penetration.

Some piping penetrations, such as those used for the steam lines, have special provisions for thermal movement. In these penetrations, the process line is enclosed in a guard pipe attached to the main steam line (MSL) through a multiple head fitting. This fitting is a one-piece forging with integral flues and is designed to meet all requirements of the ASME Code, Section III, Subsection B.

The forging is radiographed and ultrasonically tested as specified by the ASME Code. The guard pipe and flued head are designed to the same pressure requirements as the process line. The process line penetration sleeve is welded to the drywell and extends through the biological shield where it is welded to a two-ply expansion bellows assembly that is welded to the flued-head fitting. The pipe is guided through pipe supports at the end of the penetration assembly to allow steam line movement parallel to the penetration and limit pipe reactions of the penetration to allowable stress levels.

Where necessary, the penetration assemblies are anchored outside the containment to limit the movement of the line relative to the containment. The bellows accommodates the relative movement between the pipe and the containment shell.

The bellows-type expansion joints used in the containment penetrations were designed, manufactured, and inspected to ASME Code, Section III, in conjunction with Code Cases 1177-7 and 1330-2. These code cases, along with Section III, delineate the allowable stress limits for the bellows-type expansion joints and nondestructive examination requirements for bellows used in nuclear service.

The design of the penetrations takes into account the stresses associated with normal thermal expansion, live and dead loads, seismic loads, and loads associated with a LOCA within the drywell. The design takes into account the loadings given above in addition to the jet force loadings resulting from a pipe failure. Penetration design loading combinations are discussed in chapter 12.

The cold piping, ventilation duct, and instrument line penetrations are generally welded directly to the sleeves. Double-flued head fittings are used in some cases where stress analyses indicate the need. Bellows and guard pipes are not necessary in these designs, since the thermal stresses are small and are accounted for in the design of the weld joint.

5.2.2.4.3 Electrical Penetrations

Figures 5.2-5 and 5.2-6 show typical electrical penetration structural components and assembly details. All penetrations are hermetically sealed with provisions for periodic leak testing at design pressure. The penetration canisters are factory assembled and tested with the number of field welds held to a minimum.

These seals also meet the intent ASME Code, Section III, even though the Code has no provisions for qualifying the procedures or performances.

5.2.2.4.3.1 <u>Tests Performed on Electrical Penetrations to Ensure Primary Containment</u>.

A. Approximately 60 qualification tests were performed on penetrations. These tests included dielectric strength test, leak check, insulation resistance test, thermal test, short circuit test, and accident environmental test. Penetrations of this design are installed in the Oyster Creek, Nine Mile Point, Dresden 2 and 3, Quad Cities 1 and 2, and Millstone 1 Nuclear Power Plants.

B. The effects of relative expansion between the epoxy and steel were accelerated by thermocycling to simulate normal reactor startup and shutdown equivalent to 40 years of plant operation. Based on additional qualification data and reanalysis of the qualified life calculations performed for license renewal, the qualified life for the penetrations is > 60 years.

   Tests on the seal under accident environment conditions were also performed.

C. A welding thermal test simulating the field installation of the penetration assembly was performed to verify no degradation of penetration materials occurred.

D. Each type of power penetration was short-circuit tested in accordance with the requirements of Insulated Power Cable Engineers Association (IPCEA) Specification P-32-382 to ensure the penetration assemblies maintain containment integrity during and after faulted conditions.

5.2.2.4.4 Traversing Incore Probe (TIP) Penetrations

The TIP guide tubes pass from the reactor building through the primary containment. Penetration of the guide tubes through the primary containment are sealed by means of brazing that meets the requirements of the ASME Code, Section VIII. These seals also meet the intent of ASME Code, Section III, even though the Code has no provisions for qualifying procedures or performances.

5.2.2.4.5 Personnel and Equipment Access Locks

One personnel access lock provides access to the drywell. The lock has two gasketed doors in series that are designed and constructed to withstand the drywell design pressure. The doors are mechanically interlocked to ensure that at least one door is locked at times when primary containment is required. However, in case of a threat to plant personnel safety, breakglass stations are provided inside the drywell, as well as inside the airlock, with a selector switch inside the reactor building to defeat these interlocks. Breakage of the glass or operation of the selector switch is annunciated in the MCR.

The locking mechanisms are designed to maintain a tight seal when the doors are subjected to either internal or external pressure. The seals on this access opening are capable of being tested for leakage.

A bolted-in-place personnel access hatch in the drywell head contains double, testable seals. Two bolted-in-place equipment access hatches contain double, testable seals.

Personnel and equipment hatches are sized and located with full consideration of service required, accessibility for maintenance, and periodic testing programs. A 2-in. minimum gap is maintained around the barrel of the personnel and equipment hatches where they pass through or enter the concrete shield wall.

A bolted-in-place control rod drive (CRD) removal hatch with double, testable seals permits extensive maintenance of the drive mechanism, if required.

5.2.2.4.6 Access to Suppression Chamber

Access to the suppression chamber is provided at two locations via two 4-ft diameter manhole entrances with double-gasketed, bolted covers connected to the chamber by 4-ft diameter steel pipes. These access ports are bolted closed when primary containment is required and are opened only when the primary system temperature is $< 212°F$ and the pressure-suppression system is not required to be operable.

5.2.2.4.7 Access for Refueling Operations

The top portion of the drywell is removed during refueling operations. The head is held in place by bolts and is sealed with a double seal arrangement. The head is bolted closed when primary containment is required and is opened only when the primary coolant temperature is $<$ 212°F and the pressure-suppression system is not required to be operable.

The double seal on the head flange provides a method for determining leaktightness after the drywell head has been replaced.

5.2.2.4.8 Testing of Containment and Penetration Assemblies

Both the containment and the penetration assemblies are tested separately at 125% of design pressure. Only the final closure welds (bellows-to-vessel nozzle weld and in the case of the primary steam lines, the bellows-to-flued head weld) are not tested at 125% of design pressure. These welds meet all the requirements of a Nuclear Class 2 weld, including 100% radiography. Since these are circumferential welds, the pressure stress across the welds is half as much as on a longitudinal seam weld. Where the relative movement of the containment to the pipe is large, a bellows is provided so stresses in the containment nozzle due to pipe movement are low.

5.2.2.4.9 Testing of Containment Airlock

The design features for testing the containment airlock are shown in figure 5.2-7.

Tie-downs for the interior door allow the airlock to be tested at the calculated peak containment pressure. Two gaskets seal each door when closed. The gap between the gaskets can be tested to 10 psig. Pressure, temperature, and makeup air flow are measured, and the leakage rate is measured using the flowmeter. Testing is based upon the guidance of 10 CFR 50, Appendix J.

5.2.2.5 <u>Primary Containment Isolation Valves (PCIVs)</u>

5.2.2.5.1 General Criteria

PCIVs located on process lines penetrating the primary containment are designated as group A, B, or C in accordance with the following general criteria:

A. Group A - Lines Connecting to the RPV

   1. Effluent lines, such as the MSLs, have at least one power-operated valve inside and one power-operated valve outside the primary containment.

2. Influent lines have at least one check valve inside and one power-operated valve outside the primary containment. However, for influent lines in ESF systems, such as the CS injection lines, the power-operated valve outside the primary containment is considered the inboard containment isolation valve, and the closed system outside the primary containment is considered the second isolation boundary. The closed system is:

    - Protected from external missiles.

    - Designed to Seismic Category I criteria.

    - Classified as quality group B.

    - Has a design temperature and pressure rating at least equal to that of the containment.

B. Group B - Lines Opening into the Primary Containment

1. Effluent lines, such as the primary containment purge exhaust lines, have at least two power-operated valves outside the primary containment.

2. Influent lines, such as the primary containment purge supply lines, have the same arrangement as the effluent lines.

C. Group C - Lines Closed Inside the Primary Containment and Not Connected to the RPV

1. Effluent lines, such as the reactor building closed cooling water outlet line, have at least one power-operated valve outside the primary containment.

2. Influent lines, such as the reactor building closed cooling water inlet line, have the same arrangement as the effluent lines.

Exceptions to the above isolation valve criteria are as follows:

1. The feedwater lines have a check valve both outside and inside the primary containment.

2. The CRD system hydraulic lines are isolated by the normally closed hydraulic system control valves located in the reactor building and by check valves comprising a part of the drive mechanisms.

3. Group B water-sealed lines have one isolation valve in addition to the water seal. This arrangement is adequate to meet isolation requirements.

Motive power for the valves on process lines requiring two valves are physically independent sources and provide a high probability that not even a single accident can interrupt motive power to both closure devices. The valve closes on receipt of a containment isolation signal. Loss of valve actuation power is detected and annunciated.

Main steam isolation valve (MSIV) closure time is such that for the design break, coolant loss is restricted so that the reactor core remains covered.

5.2.2.5.2 Leak Detection for MSL, RCIC, HPCI, and Reactor Water Cleanup (RWC) System Isolation Valves

The temperature around the MSL is monitored by four resistance temperature detectors (RTDs) placed along the MSL piping in the steam tunnel. Cables are routed from these RTDs to trip units located in the MCR. The contacts from the trip units are wired for coincidence closure of the MSIVs on high temperature. In addition, thermocouples are mounted at the inlet and outlet of the steam tunnel to measure the tunnel ambient and temperature difference and to alarm on temperature rise. The RTD and trip units are part of the analog transmitter trip system (ATTS) discussed in section 7.18.

A differential temperature sensing system is installed in the room containing the RWC system. Temperature sensors are placed near the inlet and outlet ventilation ducts. A differential temperature switch between each set of sensors initiates an alarm in the MCR when the temperature difference reaches a point indicating leakage within the monitored room. An additional RTD and trip unit temperature sensing system provide an independent isolation signal to each isolation valve, thus satisfying the single-failure criterion. The RTDs and trip units are part of ATTS discussed in section 7.18.

The proper operation of the sensors and the logic associated with the leak detection system were verified during the leak detection system preoperational tests. Subsequent surveillance tests are performed on the various components of the detection systems as required by the Technical Specifications.

The thermocouple/RTD sensors are checked against the known existing temperature. Failure of a thermocouple/RTD by open circuit between test periods is determined by the temperature switches/trip units that indicate or alarm on open circuit.

Each temperature switch, both ambient and differential, is connected to dual thermocouple elements. Each temperature switch can be checked for operation by observing the ambient or differential temperature and turning the trip point adjustment to ensure the switch operates at the proper temperature. Each temperature switch contains a trip light that indicates when temperature exceeds the setpoint on the meter. Section 7.18 discusses testability of the RTD and trip units that are part of ATTS. Testing of the RTDs and associated logic can be accomplished without causing isolation. Using the keylock switches prevents HPCI or RCIC system isolation. Testing one channel at a time prevents isolation of the MSLs. Bypassing the isolation logic prevents isolation of the RWC system. Thus, complete system checks can be made.

When the keylock test switches are selected to the test position, the operator receives annunciation in the MCR. These switches satisfy the separation criteria outlined in Institute of Electrical and Electronics Engineers (IEEE) 279, paragraph 4.6.

In general, high-flow settings are intended to produce rapid isolation for severe rupture of steam and process lines, while the temperature setpoints are set such that small leaks in the various lines are detected. The high-flow settings preclude spurious operation while limiting any resulting site boundary doses to a value less than the value of the main steam line break accident (MSLBA) discussed in HNP-2-FSAR chapter 15, section 15.3. The temperature settings that relate to both ambient and differential conditions for the various equipment rooms (RWC, HPCI, and RCIC) are chosen so that the systems with identified leakage < 25 gal/min can be isolated. The MSL space temperature detection system is designed to detect leaks ranging from 1% to 10% of rated steam flow.

The temperature detectors in the equipment rooms are located and shielded such that they are responsive to air temperature only and are not affected by direct radiation or impingement. Differential temperatures are measured by placing temperature sensors in both the inlet and outlet ventilation ducts for the particular equipment room.

Temperature sensors are located in the outlet of the emergency area coolers in the HPCI and RCIC rooms to detect high room temperature resulting from steam leakage from the RCIC and HPCI steam lines within these rooms. Because there are no steam lines other than the HPCI steam lines in the HPCI room, and no steam lines other than the RCIC steam lines in the RCIC room, spurious isolation of HPCI or RCIC cannot result from failures of other system lines in these rooms.

A 4 x 4 array of temperature sensors that isolate only the MSLs is located above the MSLs in the steam tunnel. These sensors. To eliminate inadvertent isolation of the MSLs due to a sensor being impinged upon by a small steam leak in an MSL or a RCIC steam line that also passes through the steam tunnel, the control logic is such that two sensors must sense high temperature in a one-out-of-two-taken-twice logic to cause MSL isolation.

Final settings for the temperature sensors located in equipment areas (both ambient and differential) were determined after normal operating conditions were measured during initial plant startup.

The primary containment sump drain monitoring system is tested by supplying makeup water to the sump at a flowrate sufficient to bring the water level above the sump high-level pump actuation point in less than a predetermined time.

The only time delays associated with any of the leakage detection systems based upon temperature measurement (small breaks) are those for the HPCI steam line (15 min) and the RCIC steam line (30 min).

Each detection system is associated only with the isolation valves of the primary system it monitors; thus, complete electrical and mechanical independence exists.

Consideration of the radiological consequences associated with the time delay in isolating breaks is relevant only to the HPCI and RCIC systems as indicated above. Calculations for these systems were performed based upon the time delays mentioned and assuming flow from the break to be 300% of rated flow for the system. Additional analyses were performed to extend the analytical limit of 300% of rated flow to ~ 320%. Above this flow, no time delay exists, because isolation from the flow sensors is instantaneous.

The following radiological effects were calculated:

- RCIC steam line < 0.25% of MSLBA dose.
- HPCI steam line < 1% of MSLBA dose.

5.2.2.5.3 Description

The basic function of all PCIVs is to provide necessary isolation for the containment in the event of an AOO, accident, or special event when the release of containment atmosphere cannot be permitted.

TRM table T7.0-1 lists the PCIVs, defines valve status (normally open or normally closed) during normal reactor operation, and shows the signals required to initiate desired operation.

Isolation valves accomplish the "seal-out" completion of protective action by a circuit arrangement whereby each normally energized channel relay is isolated by its own series contact upon operation. These relays remain deenergized until the series contact is bypassed by manual reset. All other RPV isolation valves utilize the same arrangement to ensure deenergization of the channel relay coil circuit once the relay contacts have opened. This design complies with IEEE-279, paragraph 4.16.

Resetting the PCIVs following containment isolation requires operation of two manual reset switches located on adjacent panels, thereby precluding inadvertent resetting by a single operator movement or action.

Safety-related valve operators are sized for the operator to open or close the valve in the required time against the maximum differential. All motor-operated coolant isolation valves in the ECCS open on limit switches only and close on torque switches.

TIP subsystem guide tubes are provided with an isolation valve that closes automatically upon receipt of the proper signal and after the TIP cable and fission chamber have been retracted. In series with this isolation valve, an additional or backup isolation shear valve is included. Both isolation valves are located outside the drywell. The function of the shear valve is to ensure integrity of the containment even in the unlikely event the other PCIV fails to close or the chamber drive cable fails to retract if extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon an actuation signal. Valve position (full open or full closed) of the automatic closing valves is indicated in the MCR. Each shear valve is an explosive-type, dc-operated valve, with provisions for monitoring of each actuating circuit, and is operated independently.

In the event of a containment isolation signal, the TIP subsystem receives a command to retract the traveling probes for the mechanisms. Upon full retraction, the PCIVs are closed automatically. If a traveling probe is jammed into the tube run to the point it cannot be retracted, the operator can determine whether the shear valve should be operated based upon plant instrument data.

Subsequent to the requirement for containment isolation, the operator should observe a green indicating light for each TIP machine. The green light indicates associated probe is withdrawn and the isolation ball valve is closed. This lamp is illuminated when either the normal isolation ball valve or the shear valve is closed. If a green light indication is not received, the operator can attempt to withdraw the probe from the TIP control panel in the MCR. If this action fails, the operator initiates operation of the shear valve.

The requirement for containment isolation is infrequent, and the coincident use of the TIP subsystem at such time, together with a probe failing to withdraw, leads to a very low probability for the overall event. However, assuming the occurrence of such an event, the leakage path is extremely small, considering a 1/4-in. bore tube contains the TIP cable. The leakage is considered to be virtually zero and leaves adequate time for the operator to initiate the shear valves, if necessary. The automatic initiation of the shear valves is not required because of the unlikely nature of the event, coupled with the resulting minimal leakage. Furthermore, automatic initiation of these valves increases the possibility of inadvertent operation with the attendant operational problem of effecting a repair.

Each motor-operated valve (MOV) is provided with limit switches used to indicate the valves are either open or closed. Each MOV is capable of being actuated from the MCR.

The PCIVs and check valves are all purchased to the seat leakage requirements specified by MSS-SP-61, having 2 cc/h/in. of seat diameter as the maximum allowable leakage.

Except for the following exception, no valves in the primary containment and RPV isolation control system receive a LOCA isolation signal that can be manually overridden:

> The LOCA isolation signal for the primary containment atmosphere analyzer can be manually overridden. A master key system, along with valve position indicating lights, is used to control and inform the operator of the override action.

A mimic display board for only the primary containment and RPV isolation control system provides indication of isolation valve position.

When isolation occurs, all energized display lights are green. The sample line valves for the O_2 and H_2 analyzer, and the fission products monitoring system are the only valves that can be opened by overriding the isolation signal.

When the operator overrides the isolation signal for the sample line valves, the green lights are extinguished and the red lights energized to indicate the valves are open. The operator can check to see if the override has been used by checking to see if the master key is in the switch and the switch is in the override position.

The combination of red lights and the override switch position indicates the override has been initiated.

5.2.2.5.4 Instrument Lines

5.2.2.5.4.1 <u>General</u>. Sensing instrument lines penetrating the primary containment that form a part of the reactor coolant pressure boundary (RCBP) contain a 1/4-in. flow restricting orifice. The orifice is located as close as feasible to the RPV and is sized to limit the discharge from a downstream break to within the capacity of the standby gas treatment system (SGTS) without affecting instrument response. The offsite exposure from an instrument line break outside of the primary containment is well within the limits of 10 CFR 100, and no intolerable pressure transients affect the structural integrity of the secondary containment.

Outside the primary containment, the instrument lines are provided with a manually operated root valve followed by an excess flow check valve (EFCV). The valves are located as close to the primary containment as permits servicing both valves. Should a break occur downstream of the EFCV, the valve closes as the flowrate reaches a 2-gal/min maximum. Valve position is indicated in the MCR. A remotely operated bypass around the EFCV permits the EFCV to be reopened once the downstream condition is corrected.

Sensing lines penetrating and opening into the containment are provided with a manually operated root valve outside the primary containment.

Non-sensing lines penetrating the primary containment and forming a part of the RCPB are provided with two power-operated isolation valves, one inside and one outside the primary containment.

Non-sensing lines penetrating and opening into the containment are equipped with two power-operated isolation valves outside the primary containment.

Where possible, line lengths outside the primary containment are minimized as much as possible to reduce the probability of failure.

5.2.2.5.4.2 <u>Containment Isolation Requirements for Instrument Lines</u>. All instrument-sensing lines penetrating the primary containment and connecting to the RCPB are equipped with a restriction orifice located as close as is practical to the point of connection to the RCPB inside of the primary containment. A manual shutoff valve is located outside the primary containment and is installed as close as is practical to the point of exit. Immediately downstream of the manual valve is an EFCV that automatically closes for a line break downstream of the valve. Indicating lights on an MCR panel monitor the valve position. After repairs are made, the valve can be reopened by action of a solenoid attachment operated from the panel. This system fulfills the requirements of Safety Guide 11, Section C, paragraphs b, c, d, and e.

The following instrument lines penetrate the primary containment and connect to the RCPB:

- 16 lines measuring main steam flow.
- 24 lines for measuring jet pump flow.
- 9 lines for measuring RPV water level and pressure.
- 8 lines for measuring recirculation pump discharge flow.
- 8 lines for measuring jet pump header ΔP.
- 4 lines for measuring ΔP across the recirculation pumps.
- 4 lines for measuring recirculation pump seal pressures.
- 4 lines for measuring core ΔP and reference for jet pump flow.
- 4 lines for measuring steam leak detection or the HPCI turbine steam line.
- 4 lines for measuring steam leak detection for the RCIC turbine steam line.
- 2 lines for measuring recirculation pump B suction pressure.
- 2 lines for measuring CS header ΔP.
- 1 line for detecting RPV flange leakage.

Twelve lines penetrate the torus shell to supply air to piston operators on the vacuum breaker valves. These lines meet the requirements of Safety Guide 11, since they do not penetrate the RCPB and do not open to the primary containment atmosphere. One solenoid valve for each line is located close to the penetration outside the torus shell. The valves are manually controlled from the MCR.

Six lines used for measuring the hydrogen and oxygen content of the primary containment atmosphere are supplied with two isolation valves outside the containment downstream of a manual shutoff valve. An exception to Safety Guide 11 is taken, because the purpose of this system is to monitor the containment atmosphere during and after an accident. For these lines, valves are not installed inside the containment, since system reliability would be reduced. The valves may be remotely closed by manual action. Indication lights show valve positions.

Six lines connected to the primary containment measure containment pressure. Four more lines connected to the suppression chamber measure level. All of these lines are equipped with a 1/4-in. inside diameter restriction orifice inside the containment. One manual isolation valve is located outside the containment. These valves are equipped with a locking device to lock the valves in the open position. By administrative control, the position of the valves can be verified. The requirements of the supplement to Safety Guide 11, dated February 17, 1972, are met.

No instrument lines penetrate both the primary and the secondary containments.

The design and installation requirements for all instrument lines between their containment isolation valves and the sensors are the same as for the process lines.

The design requirements are stated in Appendix A, section A.3. The installation requirements are stated in section A.5. The classification of the process pipes is given on drawing no. H-16022.

Instrument lines are classified as either Seismic Class 1 or Seismic Class 2 in accordance with the criteria described in appendix A, subsection A.3.1.4. The analysis of the Seismic Class 1 piping is also described in subsection A.3.1.4. All instrument lines connected to RCPB are Seismic Class 1 up to and including the containment isolation valve.

5.2.2.6 Vacuum Relief Valves

The primary containment is designed for an external pressure not more than 2 psi greater than the concurrent internal pressure. The vacuum relief system shown on drawing no. H-16024 is of adequate size to prevent a collapse pressure in either the drywell or the suppression chamber as a result of the most rapid cooldown transient that can occur during normal operation or a postulated accident condition assuming the failure of a single active component.

5.2.2.6.1 Suppression Chamber-to-Drywell Vacuum Breakers

Vacuum in the drywell is relieved by 12 valves located on the vent header of the vent system between the drywell and the suppression chamber (figure 5.2-8). These valves are self-actuating vacuum breakers similar to simple check valves that can be locally or remotely operated for testing purposes. The position-indicating system associated with each of these valves has two closed-position indicating switches. For indicating the closed position of the valves, a local or remote pushbutton controls separate indicating lights locally and in the MCR.

Based upon the Bodega Bay pressure-suppression tests,[4] the total cross-sectional area of the main vent system between the suppression chamber and the drywell was established at a minimum of 51.5 times the total break area. The vacuum relief capacity between the suppression chamber and the drywell should be no less than approximately one-sixteenth of the total vent cross-sectional area.

5.2.2.6.2 Reactor Building-to-Suppression Chamber Vacuum Breakers

Vacuum in the suppression chamber is relieved by a vacuum breaker and an air-operated butterfly valve located in each of two lines from the reactor building to the suppression chamber. Each butterfly valve is actuated by ΔP. Each vacuum breaker is self-actuating and can be remotely operated for testing purposes.

The reactor building-to-suppression chamber vacuum breakers are sized on the basis of the required flow of air from the secondary containment that limits the maximum negative containment (drywell and torus) pressure to within design limits. The maximum depressurization rate is a function of the containment spray flowrate and temperature, and the assumed initial conditions of the containment atmosphere. Low spray temperatures and atmospheric conditions yielding the minimum amount of contained noncondensible moles of gas (air or nitrogen) are conservatively assumed.

Thus, the minimum number of noncondensible moles of gas in the drywell is specified by the condition of 150°F and relative humidity of 100% at a maximum pressure of 2 psig, which correlates to the containment spray actuation interlock.

5.2.2.7 Primary Containment Cooling System

The primary containment (drywell) cooling system utilizes six fan coil units distributed inside the drywell (drawing no. H-16007). Each fan coil unit consists of two banks of cooling coils and two direct connected motor-driven vaneaxial fans. Either fan can be used with either bank of cooling coils. One or both banks of cooling coils may be utilized for maintaining the uniform temperature. Cooling water is supplied from the plant service water (PSW) system. Table 5.2-1 provides the design parameters for the primary containment cooling system.

Fan coil units supply cooled air around the recirculation pumps and motors, the CRD area, and the annular space between the RPV and the reactor shield. Cooled air is also circulated through the RPV head area and the relief valve area.

Each fan is started from the MCR. If the normal operating fan fails, a flow switch senses low flow and starts the standby fan automatically. High air temperature from each fan coil unit is annunciated in the MCR. The fan coil units can be operated from the emergency power supply. A LOCA signal causes the fan to shut off. The operator is provided an override switch to restart the fans and coolers. In support of NRC Generic Letter 96-06, the control logic for the PSW inlet valves to the cooling coils of the drywell coolers has been modified to maintain the inlet valves in the open position for all modes of operation.

Several temperature elements monitor drywell temperature. In the event of high temperature, either of the four temperature switches initiates a start signal to the standby fan in fan coil units T47-B007A&B and T47-B008A&B. The increased airflow due to the operation of both fans in any unit would provide additional cooling. Both fans in cooling units T47-B008A&B can be operated as needed to provide additional cooling to the upper part of the drywell.

The fans, including the electric motors for units T47-B007A&B and T47-B008A&B, are qualified to operate in an environment following a LOCA. This capability can be utilized to maintain a relatively uniform environment following the unlikely event of a LOCA. The drywell fan coil units perform no active safety-related function. PSW is used as the coolant in the units. Therefore, the fan coil units are classified as safety related to passively support the pressure boundary of the service water system. Also, the PSW piping forms a closed loop within the primary containment. There are outboard containment isolation valves for both the supply and return headers. Since the cooling coils in the drywell fan coil units form a portion of the closed-loop pressure boundary, they are also classified as safety related to support the containment isolation safety-related function.

5.2.2.8 Primary Containment Purge System

The containment is vented during reactor heatup to eliminate a pressure buildup (drawing no. H-16024) and can be periodically vented thereafter to maintain pressure within operating limits during planned operations. The drywell and suppression chamber can be vented separately by drawing the primary containment atmosphere through the SGTS where the gases are stripped of their particulate and halogen contents and released via the main stack.

Clean reactor building air is supplied to the torus and the drywell for purge and ventilation purposes during reactor shutdown and refueling periods, and within 24 h of reaching < 15% of rated thermal power for fast venting to permit personnel access and occupancy. The ventilation lines supplying air to the primary containment are provided with two fast-acting pneumatic cylinder-operated butterfly valves in series for isolation purposes. These valves are normally closed during plant operation.

The containment purge supply and the main exhaust isolation valves receive isolation signals upon any of the following conditions:

- Low RPV water level - level 3.
- High drywell pressure.
- High reactor building radiation.
- High refueling floor radiation.
- High primary containment radiation.

In addition, remote manual operation of these valves is available in the MCR. These isolation valves protect against substantial releases of radiation to the environs from the drywell (section 7.3).

For both the drywell and suppression chamber exhausts, the inboard and outboard 2-in. bypass valves are not interlocked. The inboard and outboard valves receive separate isolation signals. Each emergency exhaust path isolation valve is provided with a manual override for each of the individual isolation signals via keylock switches located in the MCR. Each normal exhaust path isolation valve is provided with a manual override only for the MSL high-pressure signal via keylock switches located in the MCR.

Control air for all pneumatic equipment inside the drywell is supplied by the drywell pneumatic system described in section 10.19. This system virtually eliminates the dilution of nitrogen inside the drywell.

A pneumatic line failure resulting in a leak beyond the capacity of the drywell pneumatic system will cause the backup nitrogen system to be initiated, as described in subsection 10.19.3. An alarm in the MCR indicates initiation of the backup nitrogen system.

The drywell and torus atmospheres are vented (for the purpose of inerting with nitrogen) and purged to reduce nitrogen concentration, along with airborne and gaseous radioactivity, prior to personnel entry. Prior to purging, the primary containment atmosphere is analyzed for activity level.

Following a DBA, the purge exhaust is routed to the stack via a flow-controlled valve and the SGTS. Purging is accomplished by drawing the primary containment atmosphere through the SGTS where the gases are stripped of their particulate and halogen contents. The processed stream is then monitored by the main stack radiation system through the main stack.

Mechanical stops on the purge valves prevent the valves from being opened to > 50% of their full travel, thus ensuring the valves can be closed against the maximum containment pressure should a LOCA occur while a purge operation is in progress.

Redundant excess flow isolation dampers, in series, on the containment purge and vent line downstream of the purge valves and before the SGTS filter trains prevent high LOCA pressure from overpressurizing the filter trains in the unlikely event of a LOCA occurring during containment venting. A 2-in. bypass line around the dampers ensures a vent path is available at all times.

The torus purge vent line containing isolation valves T48-F318 and T48-F326 is the vent path from the torus for the torus hardened vent as shown on drawing no. H-16024. The torus hardened vent can be used for severe accident conditions and is not intended to be used for either normal operation or DBA mitigation.

5.2.2.9 <u>Primary Containment Nitrogen Inerting System</u>

The nitrogen inerting system provides gaseous nitrogen for inerting the primary containment (drawing no. H-16000). The system is capable of reducing the oxygen content of the primary containment atmosphere < 4% by volume. The system is also capable of maintaining the oxygen content of the primary containment atmosphere < 4% by volume during normal plant operation and following a DBA. The system consists of a liquid nitrogen storage tank; a steam vaporizer (common for both HNP-1 and HNP-2); an ambient vaporizer; a pressure-reducing valve and controller; and associated instrumentation, valves, and piping.
The system is sized to allow inerting of the drywell in a 4-h period using the steam vaporizer. The system is also sized to supply 100 sf^3/min gaseous nitrogen during normal plant operation and following a DBA using an ambient vaporizer.

Basically, the nitrogen inerting equipment in the primary containment performs three functions:

- Initially inerts the primary containment.
- Provides an automatic supply of makeup gas.
- Provides a controlled supply of gaseous nitrogen into the primary containment following a DBA.

The nitrogen inerting system also supplies nitrogen to the TIP system indexing mechanism and backs up the drywell pneumatic system and the noninterruptable instrument air system during normal plant operation.

Prior to each startup, the primary containment is purged of air with pure nitrogen. Nitrogen is supplied from either the onsite storage tank or a rented liquid nitrogen storage tank through the common steam vaporizer where the liquid nitrogen is converted to the gaseous state by heating with auxiliary steam. The gaseous nitrogen then flows through a pressure-reducing valve and flowmeter into the suppression chamber and drywell where it mixes with the air. The pressure in the primary containment during inerting does not exceed 1.25 psig.

During normal plant operation for makeup of normal leakage, nitrogen is supplied from the onsite storage tank through the ambient vaporizer where the liquid nitrogen is converted to the gaseous state by heating with ambient air. The gaseous nitrogen then flows through a flowmeter and a needle valve into the primary containment. The inerted atmosphere of the primary containment is maintained at a positive pressure < 1.75 psig during normal plant operation.

Following a DBA, nitrogen is supplied from the onsite storage tank through the ambient vaporizer. The gaseous nitrogen then flows through a flowmeter and flow control valve into the suppression chamber and/or drywell. Wherever it is possible, redundancy is provided in equipment and piping to ensure nitrogen flow into the primary containment following a DBA.

The systems for HNP-1 and HNP-2 include an individual liquid nitrogen storage system. The HNP-1 liquid nitrogen storage system is designed to back up the HNP-2 liquid nitrogen storage system, and, conversely, the storage tank for HNP-2 is designed to back up the HNP-1 storage tank.

5.2.2.10 Drywell Temperature and Pressure Indication

Drywell temperature and pressure are continuously monitored and recorded in the MCR. These instruments are used to monitor the essential drywell parameters assumed as initial values in HNP-2-FSAR chapter 15, Safety Analysis. To completely evaluate post-accident drywell pressure, three pressure ranges (table 5.2-2) are provided:

- Wide range.
- Mid range.
- Narrow range.

5.2.2.11 Suppression Pool Temperature and Level Indication

Suppression pool temperature and level are continuously recorded, and suppression pool level is continuously indicated in the MCR. These instruments can be used to monitor the essential suppression pool parameters assumed as initial values in HNP-2-FSAR chapter 15.

5.2.2.12 Primary Containment Atmosphere Monitors

Table 5.2-2 is a tabulation of variables relating to primary containment conditions that are remotely monitored, together with the relevant instrument ranges. Table 5.2-2 also provides the anticipated ranges of these variables during normal operation and post-accident conditions.

5.2.3 SAFETY EVALUATION FOR CONTAINMENT FUNCTIONAL DESIGN

HNP-2-FSAR subsection 6.2.3 provides a description of the analyses that demonstrate acceptable HNP-1 and HNP-2 containment performance.

5.2.3.1 Primary Containment Integrity Protection

The design of the primary containment and its components considers the containment integrity under the assumed accident conditions. Pertinent design considerations are as follows:

A. All large pipes penetrating the containment are designed so that anchors or limit stops located outside the containment limit pipe movement. These stops are designed to withstand the jet forces associated with the clean break of the pipe, thus, maintaining containment integrity.

B. Space between the outside of the containment vessel and the concrete is dimensionally controlled so that in areas subjected to jet forces, containment integrity is not violated. Where concrete is not available, such as at the vent openings, barriers are placed across these openings for jet protection.

C. Containment design provides the capability to also detect a small leak so that proper action can be taken before the leak develops into an appreciable break (section 4.10).

D. It is concluded that pipes will not break in a manner that will bring about movement of the pipes sufficient to damage the primary containment vessel. based upon the following:

    1. Conservative piping design using proven engineering design practice,

    2. Proper choice of piping materials, and

3. Use of conservative quality control standards and procedures for piping fabrication and installation.

Nevertheless, a system of pipe supports for the recirculation line within the primary containment limits excessive motion associated with a circumferential pipe break. A number of supports and limit stops permit thermal expansion of the pipe.

E. The design of the containment and the contained systems takes into account the potential for the generation of missiles and minimizes the possibility of containment violation.

F. Components associated with ESF equipment are independently segregated so that the failure of one component cannot cause the failure of another component. Jet deflectors protect the vent pipes connecting the suppression chamber to the drywell. The vent discharge headers and piping are designed to withstand the jet reaction force caused by flow discharge into the suppression pool.

G. The primary containment vessel is completely enclosed in a reinforced concrete structure having a thickness of 4 to 7 ft. This concrete structure, in addition to serving as the basic biological shielding for the reactor system, also provides a major mechanical barrier for the protection of the containment vessel and reactor system against potential missiles generated external to the primary containment.

1. Pipe Restraints

a. Reactor Recirculation System (RRS)

The RRS piping loops are restrained against pipe movement in the event of a pipe break. Both circumferential- and longitudinal-type pipe breaks are considered in the design of pipe restraints. The pipe breaks are assumed to occur anywhere in the system. The restraints are located and spaced to:

- Protect the primary containment pressure boundary.
- Ensure the DBA pipe break area is not exceeded.
- Ensure sufficient emergency core cooling capability for safe shut down of the reactor.

b. Main Steam and Feedwater

A feasibility study identified the location of as many pipe restraints as possible on main steam and feedwater lines inside the drywell. The results of this study showed that these lines can only be partially restrained due to space and structural limitations. Specifically, restraints are provided on the vertical risers of the main steam and feedwater lines where the sacrificial shield wall is available for anchoring the restraints. These restraints protect the CS injection lines from a rupture of the MSLs and the containment shell from a rupture of a main steam or feedwater line in this area.

2. Protective Barriers

The effects of circumferential pipe breaks at weld joints in all unrestrained pipes inside the drywell > 1 in. and forming a part of the RCPB were determined. All drywell areas where the broken pipe is postulated to contact the primary containment pressure boundary were analyzed to determine whether the broken pipe has sufficient energy to rupture the primary containment. Areas where the possibility of a primary containment rupture exists are protected by barriers consisting of steel plates reinforced by structural shapes welded to the existing drywell weld pads.

The primary containment shell and the containment spray headers are designed to withstand the jet forces resulting from a break in the largest pipe inside the containment.

3. Physical Separation

The location of essential and ESF equipment within the primary containment mitigates the consequences of blowdown jet forces and pipe whip.

The CS lines enter at the upper cylindrical portion of the drywell; whereas, the equipment associated with LPCI is located in the lower spherical portion of the drywell. The two CS injection lines are 180° apart. The two LPCI injection lines are 29 ft 4 in. apart at the closest point.

The four SRVs designated as low-low set (LLS) valves are required to function in the relief mode to mitigate the consequences of a small- or intermediate-break inside the drywell and in the LLS mode to prevent high thrust in the SRV discharge line due to any subsequent SRV activation. Each of the four LLS valves, together with its air supply (pipe, accumulator, check valve, flex hose, etc.) and its power and control cables, constitutes one target. An evaluation confirmed no postulated break that is less than the size of an SRV inlet connection can disable the LLS function.

Separation between the SRVs and their associated pneumatic supply header and cables is provided on one side of the drywell, the SRVs and associated pneumatic supply header and cables on the opposite side of the drywell, and the inboard RHR shutdown cooling valve and associated cables. No high-energy line break smaller than three SRV port areas can damage more than one of the above targets at a time. If a single failure disables a second of the above targets, one path still remains available for long-term reactor shutdown cooling and to prevent high-thrust loads from subsequent SRV actuations.

4. Analytical Methods

a. Restraint Loading

The magnitude of loads for the pipe restraint and support steel design are determined by the following formula:

$F = K_1 K_2 PA$ lb

where:

K_1 = thrust multiplication factor for the change in momentum due to a two-phase flow. A value of 1.20 is used.

K_2 = dynamic load factor to account for the effects of rapidly applied load. A value of 1.50 is used for recirculation loop pipe restraint. For main steam and feedwater, a conservative value of 1.25 was used.

P = RPV operating pressure, 1050 psig.

A = pipe internal area, in.^{2}

b. Restraint Design

Restraints and supporting steel are designed in accordance with the AISC Code, sixth edition, using a 50% increase in Code allowable stresses and forces, as described in 4.a above.

c. Barrier Design

The thickness of the protection plates was obtained by using the Stanford equation and the Ballistic Research Laboratories' formula.

5.2.3.1.1 Report on Dynamic Analysis of Supports in Primary Containment Due to Postulated Pipe Break

The dynamic analysis covers the extent of pipe whip protection provided in the containment and the design criteria used in the analysis. Additionally, the analysis summarizes the capability of HNP-1 to withstand the effects of a pipe break inside the primary containment.

Breaks are postulated to occur at the following locations in each piping run or branch run:

1. Terminal ends.

2. Intermediate locations between terminal ends where the primary plus secondary stress intensity S_N (circumferential or longitudinal), derived on an elastically calculated basis under the loadings associated with one-half safe shutdown earthquake and operational plant conditions, exceeds 2.4 S_m (design stress intensity).

3. Intermediate locations between terminal ends where the cumulative usage factor (U) derived from the piping fatigue analysis and based upon all normal, upset, and testing plant conditions exceeds 0.1.

4. Intermediate locations, in addition to the locations determined by items 2 and 3 above, selected on a reasonable basis as necessary to provide protection. As a minimum, two intermediate locations for each piping run or branch run were assumed.

The results of the analysis are not changed by considering the above criteria. Also, the cumulative usage factor (U) criterion of 0.1 represents a screening criterion so that a sufficient number of postulated break locations is developed. The screening criterion of 0.1 cumulative usage factor is not tied to the HNP-1 Facility Operating License as applied to the HNP-1 stress calculations.

The capability of HNP-1 to withstand the effects of a pipe break inside the primary containment is described below:

A. Design Description

1. Pipe Restraints

a. Reactor Recirculation System

The recirculation piping is provided with pipe whip restraints. Both circumferential and longitudinal pipe breaks were considered in the design of this restraint system.

The recirculation loop A suction line pipe whip restraint located near the lower-end elbow was permanently removed. This is justified in accordance with the NRC line break postulation criteria defined in Standard Review Plan 3.6.2, Revision 2, dated June 1987, in Branch Technical Position MEB 3-1 for ASME Code Section III Class 1 Piping Postulation of Pipe Breaks in Areas Other Than Containment Penetration. This revision eliminated requirements for postulation of arbitrary intermediate breaks in piping systems designed to ASME Code, Section III, Class 1 piping rules.

A typical pipe whip restraint is shown in figure 5.2-10. This restraint locations for the recirculation system are shown in figure 5.2-11.

b. Main Steam and Feedwater

Two restraints are provided on each of the four main steam risers and the four feedwater risers. A typical restraint for main steam and feedwater is shown in figure 5.2-12.

2. Protective Barriers

Protective barrier plates are provided in certain areas where weld pads or other appurtenances are available for attachment to prevent a broken pipe from penetrating the containment shell. In locating these barriers, circumferential pipe breaks were assumed to occur at welds.

B. Analysis of Design

The analysis of the effect of pipe breaks inside the HNP-1 primary containment took into account the restraints and barriers, and the inherent separation and protection that exists in the design. The analysis methodology employed ensured containment integrity, adequate emergency core cooling, and the ability to shut down the reactor.

1. Essential Components Requiring Protection

The essential components requiring protection are those that are part of the ESFs required to:

- Shut down the reactor.
- Isolate the RPV and primary containment.
- Provide adequate core cooling.
- Provide primary containment integrity.

2. Postulated Pipe Breaks

Pipe breaks are postulated to occur in all pipes within the RCPB > 1 in. nominal pipe size and normally pressurized when the reactor is pressurized in the following locations:

- At any point where the cumulative usage factor exceeds 0.2 (based upon normal and upset operating conditions).

- At any point where the primary plus secondary stress intensity exceeds 2.4 S_M based upon normal and upset operating conditions.

- At the terminal ends of each primary run and one additional break at the point of highest stress or usage factor.

The above criteria for break locations were taken from ANS-20 criteria. Each postulated break is a source of pipe movement and jet impingement.

Circumferential breaks are perpendicular to the pipe axis, and the break area is equal to the internal area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially, and cause displacement of the pipe in the direction normal to the break. Longitudinal breaks are parallel to the pipe axis and oriented at any point around the pipe circumference. The maximum break area is assumed to be equal to the internal area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis.

The plant is assumed to be in normal operation prior to the postulated pipe break event.

Pipe breaks were postulated to occur in pipes normally pressurized above 275 psig and/or operate at temperatures > 200°F.

3. Analysis Results

The analysis for the protection of the essential components against the effects of the postulated pipe breaks involves considering the source and the target. Each postulated pipe break location is considered as a source, and all essential components inside the primary containment are considered as targets. Each target is analyzed for the effects from each source.

The analysis results are presented in table 5.2-3. All targets are protected for at least one of the following reasons:

a. The source pipe is restrained.

b. The source and the target are physically separated.

c. The energy level in the source pipe is insufficient to cause failure of the target.

d. There is interference between the source and the target from the existing structure.

e. The target is designed for jet impingement.

f. Structural barriers are provided.

C. Design of Pipe Whip Restraints

1. Design Loads

Reference paragraph 5.2.3.1.G.4.a.

2. Design Stress

Reference paragraph 5.2.3.1.G.4.b.

3. Dynamic Analysis

a. General Electric-Designed Restraints:

The dynamic analysis of the critical case recirculation system restraints was performed to determine the adequacy of these restraints under pipe rupture loading. Experience previously gained on Fermi-II , where similar restraints are used, was employed to help isolate the worst-case loadings. These were found to be in three restraints of the recirculation pump suction line from the RPV. The first restraint was analyzed for breaks at the recirculation outlet nozzle on the RPV and at the elbow ahead of the restraint. The second restraint was analyzed for a pipe break at the RHR tee connection, and the third restraint was analyzed for a break at the elbow between the restraint and the recirculation suction valve. The loads and the corresponding restraint deflections for the cases analyzed are presented in table 5.2-4.

All circumferential breaks noted in table 5.2-4 are assumed to occur instantaneously. All longitudinal breaks are assumed to occur instantaneously and are equal to the cross-sectional area of the pipe. The restraint-to-pipe clearance selected for the analysis was 0.75 in., to accommodate any motion. This selection is conservative since the installed clearance is 0.5 in.

The results of the dynamic analysis show that the maximum deflection of the restraint occurs for a longitudinal break at the RHR connection in the recirculation suction line. Only the second restraint was assumed to carry the resulting load with no credit being taken for other restraints on the piping run. This, with the assumption of an instantaneous opening of the pipe to the full-break area, is very conservative. In all cases analyzed, the restraint deflection is < 4.16 in., which corresponds to the deflection required for restraint failure. The margin on energy capacity is estimated at

30% for the worst case that is sufficient for the conservative assumptions employed.

Description of Method

An instantaneous circumferential or longitudinal break is the event that initiates the pipe/restraint system response. The instant the break occurs, and before any movement can take place, the broken pipe assumes the configuration shown in figure 5.2-13 (if the break is circumferential), while the broken pipe assumes the configuration shown in figure 5.2-14 if the break is longitudinal. Several elements are shown in these sketches. In either case, the thrust load, F_t, is the forcing function that activates the system response. This load, which can vary with time, acts along a line perpendicular to the break area and is applied at the break.

The circumferential break pipe/restraint system is described first because it is the simpler of the two. The break area in this system may be at the end of the pipe tail, which can be some distance from an elbow or significant change in direction. The pipe immediately upstream of the elbow is loaded as a cantilever whose point of fixity is the next elbow, the nonpiping component element such as a pump, vessel, or containment penetration. The weight of these pipes is small compared to the thrust load. Therefore, gravitational forces are neglected in the model. However, the inertial effects of these masses to the applied load cannot be neglected. Therefore, the weight of the pipe tail and any fitting, valve, or other concentrated load located within the tail is treated as a point mass applied to the end of the beam section.

The weight of the beam section is treated as a distributed load, which includes the weight located between the point fixity, and the restraint is treated as an additional distributed mass. If the concentrated weight in the beam is between the restraint and the broken end, it is treated in the model as an additional point mass transferred to the end of the beam. The restraint closest to the broken end provides controlled deceleration of the pipe masses. Any other restraint along the beam section of pipe is neglected in the analysis. However, the restraint can be either included as a guide or installed to protect against other potential breaks.

The break shown in figure 5.2-14 is a longitudinal break along the outside bend of the elbow. The model element is generally similar to the elements of the circumferential break. However, an additional element, the equivalent beam restraint, L_3, can be discerned in figure 5.2-14. This element shares the applied load with the beam element from the instant the break occurs. The applied load in figure 5.2-14 has two components, F_{BA} and F_{BB}.

- F_{BA} acts parallel to the axis of the equivalent restraint beam restraint beam ends in a true point of fixity; i.e., a vessel, containment penetration, etc., it will load some other combination of beams and equivalent and places it in compression. Unless the equivalent restraint beam. The tail of the case presently considered becomes one of the beam elements of this new system.

- F_{BB} acts perpendicular to the equivalent restraint beam and to the beam. The pipe tail and beam are similar to the element previously defined for the circumferential break and need not be further discussed. The equivalent restraint beam is treated in the model as a beam spring whose force is directly opposite to the thrust load. However, its mass cannot be neglected. Therefore, the beam is treated along with any concentrated loads it contains and an additional equivalent point mass applied to the end of the beam section.

The model makes two additional assumptions:

- Because the break region has no bending resistance, it acts as a pinned connection.

- From the above assumption, the linear displacement and velocities of the equivalent restraint beam end are equal to the total linear displacement and velocities of the end of the beam.

The model recognized the following pipe modes of response:

1) Mode 1 is the free movement of the pipe system before it contacts the restraint. In this mode, the energy that is not absorbed as deformation energy of the beam in the circumferential break and of the beam and equivalent beam restraint in the longitudinal break is stored as kinetic energy of the beam system.

2) The instant the pipe hits the restraint the system passes from the first response mode to the second response mode. This is the most complex mathematical model, because the multilink response of the system required a LaGrangian transform solution for the acceleration of the various components of the system. In mode 2, the independent variable is a small time step interval. During this interval, the thrust force, restraint forces, and pipe bending resisting moments are considered constant. The accelerations, velocities, and displacements at the broken end of the pipe are computed. The displacement at the restraint is compared to its value during the previous time interval.

a) If the current value is less than its previous value, the restraint is assumed to have reached its maximum displacement and stopped. Therefore, the third mode of response is analyzed.

b) If the current value of the restraint displacement is greater than its value in the previous time interval, the relative magnitude of the displacement of the free end of the pipe is checked.

c) If the current displacement of the free end of the pipe, relative to the bound section, is less than its value in the previous time interval, the free end is assumed to have reached its maximum relative displacement. Therefore, the fourth mode of response is analyzed.

d) If the current free beam displacement relative to the bound beam displacement is greater than its previous value, new values of the forces and moments are calculated. The process is repeated for the next time interval.

3) In mode 3, the restraint and bound end of the pipe stopped; however, the free end is still in motion. In this mode, the independent variable is a small displacement step. During each displacement step, the forces and moments of the various load elements are computed, and the energy balance is computed and checked to ensure the kinetic energy is positive.

a) If the energy is positive, the velocities and displacement time interval are calculated, and the process is repeated for the next displacement interval.

b) If the kinetic energy is zero or negative, the free end is assumed to have stopped.

4) In mode 4, the motion of the free end of the beam relative to the bound end is zero. The independent variable is a small displacement, and the computation sequence is the same as in mode 3.

5) Mode 5 is the steady-state response. The model compares the steady-state load to the maximum allowable restraint load. A comparison of the allowable restraint deflection to the actual restraint deflection is made. If the actual load and deflection are less than the maximum allowable, the requirements are satisfied.

b. Bechtel-Designed Restraints

A dynamic analysis of a typical pipe whip restraint of the feedwater system is carried out based upon a two mass-two spring system as shown in figure 5.2-15. A circumferential break with a thrust force equal to 1.5 PA is assumed in the analysis. The thrust force is assumed constant throughout with no rise time. The restraint is made of a U-shaped 2-in.-thick steel plate welded to a steel box at the bottom of the legs. The thrust force is radially applied at the center of the U-shaped plate as a concentrated load, which is the worst condition that can be expected. The dynamic analysis is performed rigorously at each stage of changing stiffness in the system, and the dynamic deflection after it passes both yield points of the pipe and the restraint takes the following form:

$$Y_{max} = \frac{y_g\left(2F - k_p y_g\right)\left(1 - \frac{m_P}{m_t}\right) - k_p y_p^2 - k_r\left(y_r^2 - y_g^2\right)}{2\left[F - k_p y_p - k_r\left(y_r - y_g\right)\right]}$$

The substitution of all known quantities into the above expression gives:

y_{max} = 3.74 in.

which indicates a ductility ratio of 15.

Comparing this maximum deflection with the allowable ultimate deflection, 5.07 in., which is computed using 50% of the ultimate strain, we conclude that the design of the restraint is adequate.

D. Design of Protective Barriers

The protective barriers provided in the containment consist of reinforcing plates attached to weld pads or other appurtenances to receive the postulated ruptured pipe, absorb a portion of the impact energy, and distribute the impact load over an area of the drywell shell such that the combined energy absorption capability of the barriers and the drywell shell is greater than the impact energy of the ruptured pipe.

The impact energy potential to the drywell shell is a function of the jet reaction force, the plastic moment of the pipe, and the configuration of the pipe with respect to the drywell. No credit is taken for the energy absorbed by pipe deformation on contact with the drywell shell.

The impact energy, E_I, is the energy available at the point of impact and can be expressed as follows:

$$E_I = E_T - E_P$$

where:

E_T = total energy of the moving pipe, $E_T = KPAS$

E_P = energy dissipated after formation of the plastic hinge, $E_P = M_P\,\theta$

K = thrust multiplication factor; $K = 1.2$ for saturated steam or water

P = normal operation pressure

A = flow area of the pipe

S = distance traveled by the pipe

M_P = plastic moment of the pipe

θ = angle through which pipe moves

The energy required for perforation of the drywell shell was determined from an empirical formula developed by Ballistic Research Laboratory.

The missile diameter is assumed to be the nominal pipe diameter. Because of the uncertainty involved in determining the missile diameter, an additional safety margin is provided in the thickness of the barrier plates.

A summary of the analyses is presented in table 5.2-5. The arrangement of the protective barriers is shown on drawing no. H-15006.

5.2.3.2 Penetrations

Containment penetrations are designed to withstand the normal containment environmental conditions, which may prevail during plant operation, and to retain their integrity during all postulated accidents.

Pipe lines that penetrate or open into the containment shell and are capable of exerting a reaction force due to line thermal expansion or containment movement that cannot be restrained by the containment shell are provided with a bellows expansion seal. These lines are anchored outside the containment to limit the movement of the line relative to the containment. The bellows accommodates the relative movement between the pipe and the containment shell. Figure 5.2-1 shows detail of the pressure test connection on the penetration sleeve and not on the outer ply of the bellows. Due to this position, the pressure rating or life expectancy of the bellows is not affected, and minimization of the forces and stresses during pipe movement is not needed.

Pipe lines penetrating the containment where the reactive forces can be restrained by the containment shell are provided with full-strength attachment welds between the pipe and the containment shell. These penetrations are designed for long-term integrity without the use of a bellows seal. A personnel access lock with interlock double doors provides access to the containment while the reactor primary system is pressurized. Double doors ensure containment integrity is effective while access is made.

Access hatches are sealed in place, using flexible double seals to ensure leaktightness. These openings are closed at all times when containment is required.

Inspection and surveillance provide additional assurance of the integrity and functional performance of the penetrations. For this reason, all electrical penetrations, the personnel access lock, the access hatches, and pipe penetrations having bellows seals can be individually leak tested without pressurizing the entire containment system.

5.2.3.3 Primary Containment Isolation

One of the basic purposes of the primary containment system is to provide a minimum of one protective barrier between the reactor core and the environmental surroundings subsequent to an accident involving failure of the piping components of the reactor primary system. To fulfill its role as a barrier, the primary containment is designed to remain intact before, during, and after to any DBA of the process system installed either inside or outside the primary containment. The process system and the primary containment are considered separate systems; however, where process lines penetrate the containment, the penetration design has the same integrity as the primary containment structure itself. The process line isolation valves are designed to achieve the containment function inside the process lines when required.

Since a rupture of a large line penetrating the containment and connecting to the reactor coolant system (RCS) may be postulated to take place at the containment boundary, an isolation valve for that line is required to be located within the containment. This inboard valve in each line is required to be closed automatically on various indications of reactor coolant loss. A certain degree of additional reliability is added if a second valve, located outboard of the containment and as close as practical, is included. This second valve also closes automatically if the inboard valve is normally open during reactor operation. If a failure involves one valve, the second valve is available to function as the containment barrier.

By physically separating the two valves, there is little likelihood that the failure of one valve will cause the failure of the second valve. The two valves in series are provided with independent power sources.

It is neither necessary nor desirable that every isolation valve close simultaneously with a common isolation signal. For example, if a process pipe ruptures in the drywell, it is important to close all lines open to the drywell, in addition to some effluent process lines, such as the MSLs. However, under these conditions, it is essential that containment and core cooling systems are operable. For this reason, specific signals are utilized for isolation of the various process and safeguards systems.

Isolation valves must be closed before significant amounts of fission products are released from the reactor core under DBA conditions. Because the amount of radioactive material in the reactor coolant is small, fission product release is limited by closing the isolation valves before the coolant drops below the top of the core.

5.2.3.4 Control of Combustible Gas Concentrations in Containment Following a LOCA

See HNP-2-FSAR paragraph 6.2.5.6.

5.2.4 INSPECTION AND TESTING

This subsection describes the inspection and tests performed for the various systems and components of the primary containment.

5.2.4.1 Primary Containment Integrity and Leak Tightness

Fabrication procedures, nondestructive testing, and sample coupon tests were made in accordance with the ASME Code, Section III, Subsection B. The integrity of the primary containment system was verified by a pneumatic test of the drywell and suppression chamber at 1.25 times the design pressure of 56 psig in accordance with Code requirements.

After complete installation of all penetrations in the drywell and suppression chamber, the RPV was pressurized to the peak calculated pressure and measurements taken to verify the integrated leakage rate from the RPV did not exceed 1.2%/day. Since both the drywell and suppression chamber are designed for the same pressure, the entire primary containment can be tested simultaneously, without the necessity of providing temporary closures to isolate the suppression chamber from the drywell. Provisions are made to permit periodic leakage rate retests.

The containment leak test program is performed in the manner described in BN-TOP-1[523] or ANSI/ANS-56.8-2002[22]. The test program is in compliance with Appendix J of 10 CFR 50[19], Reactor Containment Leakage Testing for Water Cooled Power Reactors. Some valves, such as feedwater check valves, are local leak tested by filling the test volume with water and pressurizing the test volume at a minimum of 1.1 times the peak calculated pressure. This procedure satisfies the intent of Appendix J for valves that were not originally purchased to be leak tight with air at high pressure.

5.2.4.2 Penetrations

Pipe penetrations that must accommodate thermal movement are provided with expansion bellows, such as the penetration shown in figure 5.2-1. By use of the pressure test tap, a gas (nitrogen, or other as required for leak detection) can be injected into the annulus, and by soap film, pressure decay, or other means, leakage can be detected and measured during shutdown, without pressurizing the entire primary containment system. The test tap is plugged during normal operation to prevent leakage through the test tap plug in the event of a leak within the penetration.

Electrical penetrations are also provided with double seals and are also separately testable. The test taps and seals are located so that the tests of the electrical penetrations can be conducted without entering or pressurizing the drywell or suppression chamber.

All containment closures fitted with resilient seals or gaskets are separately testable. The covers on flanged closures, such as the equipment access hatch cover, the drywell head, the access manholes, and personnel airlock doors, are provided with double seals and a test tap that allow pressurization of the space between the seals without pressurizing the entire containment system.

All testable penetrations and containment closures fitted with resilient seals are local leak tested in accordance with the Technical Specifications. Testing is performed at the peak calculated accident pressure.

5.2.4.3 Isolation Valves

A. The test capabilities incorporated into the primary containment system to permit leak detection testing of containment isolation valves are separated into two categories.

   1. Pipe lines that open into the containment and are not connected to the RPV.

      In lines containing two power-operated isolation valves in series, a test tap located between the valves permits leakage monitoring of the first valve when the containment is pressurized. The test tap can also be used to pressurize between the valves to permit leakage testing of both valves simultaneously.

   2. Pipe lines connected to the RPV.

      In lines containing two power-operated valves in series, a test tap located between the valves permits leakage monitoring of the first valve when the RPV is pressurized. The test tap can also be used to pressurize between the valves to permit leakage testing of both valves simultaneously when the RPV is not pressurized.

      In lines containing one inboard check valve and one outboard power-operated valve, a test tap is located opposite the containment side of the outboard valve. Leakage through the inboard check valve can be monitored through the test tap by opening the outboard valve when the RPV is pressurized. Leakage through the outboard valve can be monitored by opening the inboard check valve when the RPV is pressurized.

B. Isolation valve closing time is determined during the functional performance test prior to reactor startup.

C. A test connection located between the two series check valves in each of the reactor feedwater lines is used to leak test the outboard check valve with the inboard gate valve closed.
Another test connection located on the RPV side of the inboard check valve between the inboard check valve and gate valve is used to test the inboard check valve with the inboard gate valve closed.

For other leakage paths that branch off the feedwater lines between the two check valves, at least two isolation valves in series is closed to minimize leakage. The test connection between these two closed valves is open, and any significant detected flow is measured with a flowmeter. All other flow measured by the local leak test flowmeter is assigned to the outboard feedwater check valve.

D. A test connection is provided between the two valves in the reactor building-to-suppression chamber vacuum relief lines. With the inner air-operated valve held shut, leakage past the outer check valve is measured. Each of the two parallel lines is tested individually. Thus, if the plant is in operation during the tests, vacuum breaker capability is still effective.

E. All valves in the primary containment purge inlet and outlet lines, and the suppression chamber vacuum breaker lines are air-actuated containment isolation butterfly valves having valve seats of a rubber-type material, Ethylene Propylene Dienyl Monomer (EPDM). The EPDM remains functional at 300°F and 150 psig. The results of gamma radiation exposure tests show that EPDM is suitable for this application.

5.2.4.4 Bypass Leakage - Suppression Pool

The capability of the HNP-1 containment system to withstand leakage paths between the drywell and wetwell was evaluated. In the event of a primary system rupture, leakage paths will result in blowdown steam passing directly to the wetwell free space without being condensed in the suppression pool. Since the design pressure of the containment is predicated on the experimentally verified assumption that all the blowdown steam is condensed in the suppression pool, the existence of sufficiently large bypass paths can result in the containment design pressure being exceeded.

Figure 5.2-16 shows the bypass leakage capacity that can exist in the HNP-1 containment without the containment design pressure being exceeded. This curve is based upon the same assumptions as the assumptions described in the response to question 5.1, Browns Ferry Amendment 24.

Figure 5.2-16 consists of two curves, one for primary system ruptures > 0.4 ft^2 and one for smaller ruptures. Primary system breaks > 0.4 ft^2 result in automatic depressurization of the

RPV due to fluid loss and/or ECCS operation. For these breaks, the allowable leakage capacity is determined by examining the magnitude and duration of the ΔP across a postulated downcomer leakage path. The allowable leakage path is the one that results in the containment being at design pressure at the end of blowdown. This procedure is modified for very large breaks. A very high drywell pressure overshoot occurs during the early stages of the blowdown, and whether the minimum allowable leakage path is controlled by this point or by the end of blowdown analysis must be determined. Figure 5.2-17 shows the two cases.

The most limiting case depends upon the magnitude of the pressure overshoot, the duration of blowdown, containment geometry, etc. In the case of an HNP-1 DBA, the overshoot condition is the most limiting and results in an allowable leakage capacity of $A/\sqrt{K}$ = 0.43 ft^2. This allowable leakage capacity was derived by the following analysis and using the following containment parameters and pre-LOCA conditions:

- Drywell volume, VD — 143,700 ft^3[(a)]
- Wetwell air volume, VW — 110,400 ft^3[(a)]
- Drywell temperature, TD — 135°F[(b)]
- Wetwell temperature, TW — 95°F[(b)]
- Drywell pressure, PD — 0.75 psig
- Wetwell pressure, PW — 0.75 psig
- Drywell relative humidity, ϕD — 0.2
- Wetwell relative humidity, ϕ — 1.0
- Vent submergence, H — 3.7 ft

Application of the gas laws shows that the total mass of noncondensible gases in the system is 17,600 lb. Very early following a DBA, all drywell air is swept over to the wetwell, resulting in a wetwell pressure of 39 psia (assuming 100% relative humidity at 145°F). The peak drywell pressure is 58.7 psig. For this containment, the maximum allowable pressure is 62 psig. Thus, the maximum allowable leakage capacity is defined as the leakage path that results in a pressure increase (at 11 s) of 3.3 psi. Since the pressure drop through the vent system is essentially constant, it becomes a matter of determining what leakage path will result in an increase in the wetwell pressure of 3.3 psi at 11 s; i.e., how much steam will be required to do this and what leakage path will result in this mass of steam being injected into the wetwell.

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a. This value was used in the original LOCA analysis. See HNP-2-FSAR table 6.2-1 for the actual volumes following completion of the torus modifications.
b. Justification for the leakage testing criteria is not significantly affected by an increase in suppression pool temperature or drywell limits to 100°F and 150°F, respectively.

The former question can be answered by a simple application of the gas laws. If all the air in the wetwell compressed by 3.3 psi, a volume reduction of 9300 ft^3 results. This space accommodates 930 lb of steam and accounts for the allowable leakage during the first 11 s of the transient. It is assumed the air and steam do not mix, since the steam leakage enters the torus at one leakage point for only 11 s. This is a valid assumption since, a fully mixed air and steam mixture gives essentially the same allowable steam mass.

The vent pressure drop during the first 11 s of the transient is essentially constant at 36 psi; thus, a postulated leakage path would experience a constant ΔP of 36 psi for 11 s. Therefore, the flowrate through a leakage path can be approximated by the following equation:

$$\dot{m} = \frac{A}{\sqrt{K}}\sqrt{\frac{2g\Delta P144}{\bar{\nu}}}\frac{lb}{s}$$

where:

$\bar{\nu}$ = specific volume of fluid (ft^3/lb).

$\dot{m}$ = flowrate (lb/s).

A = flow area of leakage path (ft^2).

K = total flow loss coefficient.

g = 32.2 (ft^2/s).

ΔP = differential pressure ($lbf/in.^2$).

In evaluating this equation, the leakage capacity ($A/\sqrt{K}$) that passes 930 lb of steam in 11 s, with a ΔP of 36 psi, is 0.46 ft^2, based upon a 95°F suppression pool temperature.

The suppression pool temperature limit for normal operation was increased to from 95°F to 100°F. This increase will have a small effect upon the analysis presented in this section.

It is assumed the acceptable leakage area will be slightly reduced with the higher pool temperature limit. The plant Technical Specifications limit the permissible leakage to the equivalent of a 1-in. orifice, with a 1-psi ΔP. Since this leakage is < 2% of the computed acceptable flow area, the slight reduction due to the pool temperature increase will not be significant.

It should be noted that although the above analysis is not exact, it yields a conservative lower limit on the allowable leakage capacity that can exist during an HNP-1 DBA. The vent ΔP is not constant at 36 psi. If the average vent ΔP used is less, a larger allowable leakage will result. Similarly, the use of the incompressible flow equation is conservative in that it maximizes the flowrate per unit area.

The above analysis is applied to several large blowdowns to generate the right portion of the curve shown in figure 5.2-16. In the event significant variations in the ΔP between the drywell and wetwell occur during the course of the blowdown, the variations are approximated by a series of constant differentials, and the mass of steam to the wetwell, M, is calculated by:

$$M = \sum \frac{\Delta t_i A}{\sqrt{K}} \sqrt{\frac{2g\,\Delta P_i\,(144)}{\bar{\nu}}}$$

where:

Δt_i = time period for which ΔP is approximately constant at ΔP_i.

It should be noted that a key, very conservative assumption in these analyses is that none of the bypass steam is condensed. This assumption is conservative, because during a large reactor blowdown, the suppression pool surface is very agitated and undoubtedly condenses some of the bypass steam. The effect is to raise the allowable leakage capacity.

Figure 5.2-16 shows the most limiting (small break) leakage associated with small reactor blowdowns. Because the transients involved with this size break are much milder than the transients associated with the DBA and large breaks, the calculation of the allowable leakage is much more exact.

The Browns Ferry reference describes the sequence of events assumed to occur following a small reactor rupture that does not result in automatic depressurization of the reactor due to either loss of fluid or ECCS activation. Immediately following the break, drywell pressure increases and clears the vent downcomers of water. The break flow rapidly purges the drywell air into the wetwell; i.e., a 0.025 ft^2-break will accomplish this in < 3 min. Subsequently, continued blowdown of steam passes through the downcomers and is condensed in the suppression pool. In addition, if a bypass path is postulated to exist, steam enters the wetwell because of the 1.7-psi vent submergence hydrostatic ΔP that exists between the drywell and suppression chamber. This bypass flow results in continued pressurization of both the drywell and wetwell, even though the ΔP between them remains constant at 1.7 psi. When the drywell pressure reaches 35 psig, the operators are alerted that a leakage path exists, since the pressure can never reach this amount with just a simple purge of the drywell air to the wetwell. Additionally, it is assumed there is a 10-min delay before the operators act and an additional 5-min delay before the operators terminate the pressure increase by either activating sprays, depressurizing the RPV, or eliminating the source of leakage. The leakage path between the drywell and the wetwell is 0.14 ft^2 $A/\sqrt{K}$ and is based upon the drywell pressure increasing from 35 psig to 62 psig within 15 min, with a ΔP across the leak of 1.7 psi. This value is derived using the following analysis:

It is assumed all the drywell air is in the wetwell (conservative because any air in the drywell allows more steam into the wetwell), drywell pressure is 35 psig, and wetwell pressure is 33.3 psig. At this pressure, and assuming 100% relative humidity at 95°F, the noncondensibles will occupy 76,700 ft^3. Thus, there will be 33,700 ft^3 of steam (3800 lb) at the time the operators are alerted to the problem.

The above analysis is based upon the assumption that the steam and noncondensibles are not mixed. This is a realistic assumption, since the steam leakage is from a discrete source. Again, a complete mixing analysis yields essentially the same answer. Within 15 min, drywell pressure terminates at 62 psig. At this time, wetwell pressure is 60.3 psig, and the stratified noncondensibles occupy 55,000 ft^3 (100% relative humidity at 145°F). There will be 9550 lb of steam that occupies 55,000 ft^3. Thus, in the 15-min drywell rise, the wetwell steam mass increases to 5750 lb. The capacity of the resulting leakage path in the wetwell 5750-lb steam increase during this time period, with a constant ΔP of 1.7 psi, is determined from the following equation:

$$\frac{5750}{15 \times 60} = \frac{A}{\sqrt{K}} \sqrt{\frac{2g \times 1.7 \times 144}{\bar{\nu} \times g}}$$

If the average steam specific volume at the start and end of the 15-min period is used, this equation yields $\left(A / \sqrt{K}\right)$ = 0.14 ft^2. Again, it should be noted that no credit is taken for any condensation of the bypass steam on either the suppression pool surface or the suppression chamber walls.

If it is assumed the postulated bypass path is an orifice, the capacity leakage path of 0.14 ft^2 translates into 0.23 ft^2 or a 6 1/2-in. diameter orifice. The leak test used for the HNP-1 containment is sensitive enough to detect a 1-in. orifice. This represents only 2.5% of the limiting (small break) leakage capacity. Thus, it can be concluded that considerable margin exists between the leakage path tolerated and the leakage path detected by the proposed leakage test.

When comparing figure 5.2-16 and the similar curve for HNP-2, it should be noted that figure 5.2-16 shows a leakage area with an assumed a loss coefficient of 0.6. Since the use of the capacity leakage path calculation $\left(A / \sqrt{K}\right)$ with the need to discuss the geometry and loss coefficients of a postulated leakage path, it is believed to be a more useful indicator of allowable leakage.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

REFERENCES

1. "Safety Evaluation Report Mark I Containment Long-Term Program," NUREG-0661, U.S. Nuclear Regulatory Commission, July 1980.

2. "Formulas for Stress and Strain," Roark, 4th Edition, pp 370 and 371.

3. "The General Electric Pressure Suppression Containment Analytical Model," NEDO-10320, Supplement 2, General Electric Company, January 1973.

4. "Additional Information - Pressure Suppression Concept," Proprietary Topical Report, NEDM 10163.

5. “General Electric Model for LOCA Analysis is accordance with 10CFR50, Appendix K,” NEDC-20566P-A, General Electric Company, September 1986.

6. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

7. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

8. “Edwin I. Hatch Nuclear Plant Units 1 and 2 Containment Analyses for GNF3 New Fuel Introduction,” 004N8577, Revision 0, November 2018.

TABLE 5.2-1

PRIMARY CONTAINMENT COOLING SYSTEM DESIGN PARAMETERS

	Normal	Maximum[a]
Drywell	135°F	148°F
Recirculation pump motor area		128°F
Entering air temperature to cooling units	135°F	148°F
Leaving air temperature from cooling units	97°F	102°F
Cooling water supply temperature	90°F	97°F
Cooling water return temperature	100°F	110°F
Drywell heat load	3.7×10^6 Btu/h	4.5×10^6 Btu/h
Total cooling unit capacity	4.4×10^6 Btu/h	6.6×10^6 Btu/h
Total cooling unit fan capacity	82,000 ft^3/min	123,000 ft^3/min
Total fan brake	90 hp[b]	140 hp
Drywell temperature 10 h after shutdown	105°F	104°F

a. As a result of the extra heat load from the CRD scram, as well as higher cooling water supply temperature. Note that the safety analyses (reference 5) support a 150°F initial drywell average air temperature.
b. Fan horsepower for one fan per cooling unit. Each unit has two fans.

TABLE 5.2-2 (SHEET 1 OF 2)

PRIMARY CONTAINMENT ATMOSHERE MONITORS – INSTRUMENT DATA

Variable[a]	Instrument Range and Measurement Units	Range of Values in Normal Operation	Range of Values in Post-Accident Condition
Pressure			
Drywell			
(wide range)	0-250 psig	0 – 0.75 psig	0.0 – 59 psig
(mid range)	-10/0/90 psig	0 – 0.75 psig	-0.5 – 59 psig
(narrow range)	-5/0/5 psig	0 – 0.75 psig	-0.5 – 5 psig
Suppression chamber	-10/0/90 psig	0 psig	-0.5 – 28 psig
Temperature			
Drywell (air)	0 – 500°F	135°F normal/ 150°F maximum	290°F
Suppression chamber water[b][c]	0 – 500°F	≤ 100°F	95 – 200°F
Suppression chamber water average bulk[b,c]	50 – 250°F	≤ 100°F	95 – 200°F
Suppression Chamber Water Level			
(wide range)	0 – 300 in. WC	146 – 150 in. WC	
(narrow range)	133 – 163 in. WC	146 – 150 in. WC	
Oxygen Concentration			
Drywell	0 – 10%	< 5%	< 5%
Suppression chamber	0 – 10%	< 5%	< 5%
Hydrogen Concentration			
Drywell	0 – 10%	Negligible	
Suppression chamber	0 – 30%	Negligible	
Fission Products			
Particulate and iodine	$10 – 10^6$ cpm	$\geq 1 \times 10^{-9}$ µCi/cc	
Noble gases	$10 – 10^6$ cpm	$\geq 1 \times 10^{-6}$ µCi/cc	$\leq 1 \times 10^{-5}$ µCi/cc
Drywell Radiation			
(wide range)	$10^0 – 10^7$ R/h	≤ 8 R/h	$\leq 1.3 \times 10^6$ R/h

TABLE 5.2-2 (SHEET 2 OF 2)

a. All variables are monitored by two systems for redundancy. Additional information on some monitors is provided in chapter 7.
b. Reference HNP-2-FSAR subsection 5.5.7 for a discussion of suppression pool temperature monitoring.
c. The suppression pool temperature limit for normal operation is 100°F; however, the temperature is normally $\leq$ 100°F.

TABLE 5.2-3 (SHEET 1 OF 3)

RESULTS OF ANALYSIS FOR PROTECTION OF ESSENTIAL COMPONENTS AGAINST EFFECTS OF POSTULATED PIPE BREAKS

SOURCE (Note 1)	RPV Level Instruments (Note 3)	ADS (Note 4)	CRD Lines (Note 5)	HPCI (Note 6)	CS (Note 7)	LPCI (Note 8)	Primary Containment (Note 9)
Recirculation (Note 2)	S	NR	NR	S	S	S	J
Main steam	R	NR	S	S	R	S	P,X
Feedwater	R	NR	S	R,S	R,S	X	P,X
RHR discharge (LPCI)	S	NR	NR	S	S	S	P
RHR suction	S	S	S	I	S	X	P
Core spray	S	S	S	S	S	X	X
HPCI steam	S	S	S	NA	S	X	X
RCIC steam	S	S	S	X	X	X	X
RWC	S	S,I	S	X	X	X	X
CRD return	S	S	S	X	X	X	X
Steam drain	S	S	S	X	X	X	X
RPV Drain	S	S	S	X	X	X	X
Standby liquid	S,I	S	S	X	X	X	X
RPV vent	S	S	S	X	X	X	X

TABLE 5.2-3 (SHEET 2 OF 3)

LEGEND

I - interference from the existing structure
J - target designed for jet impingement
NA - not applicable
P - target protection provided (barriers)
R - source pipe restrained
S - separation of target and source
X - no failure of target (X-I)
NR - target not required if source breaks

NOTES:

1. The energy level in a source pipe is considered insufficient to damage:

    - An impacted target pipe of same or greater size and having greater wall thickness.
    - A target if the fluid jet from the broken end cannot be sustained.

2. The recirculation piping is restrained such that a broken pipe cannot reach any target. This source is, therefore, considered for jet impingement effects only.

3. RPV level instrumentation lines are protected from various sources mainly by separation from the sources.

4. The electrical cables for the ADS valves are protected from breaks in small pipes by separation from these sources. Protection from breaks in large pipes is not required since a large break will depressurize the reactor.

5. RPV pressure is adequate to scram the control rods except, at initial pressures < 450 psig, the insertion may not be achieved within the required time frame. Pipe breaks at these reduced pressures are considered incredible. No additional protection is required.

6. The HPCI system is required for small or intermediate pipe breaks, and is protected from the larger sources by separation. The smaller sources cannot damage this system.

7. The core spray system is protected from the larger sources by separation or restraints. The smaller sources cannot damage this system. These systems are physically separated from each other.

8. LPCI is protected from the recirculation and the main steam lines by separation. Other sources are not large enough to damage. These systems are physically separated from each other.

TABLE 5.2-3 (SHEET 3 OF 3)

9. The primary containment is designed to take jet impingement from any source. The smaller pipes cannot damage the primary containment. It is protected from some of the larger sources by providing structural barriers to prevent impact of the pipe on the containment or absorb sufficient energy so that the containment is not penetrated. Each case of postulated pipe impact on the containment, with or without a barrier, was analyzed to determine the energy required to penetrate the containment shell. The energy generated by the broken pipe was also calculated. In each case, the energy available is not sufficient to penetrate the containment.

TABLE 5.2-4

RECIRCULATION SUCTION LINE

Restraint No.	Cable Size (in.)	No. of Cables	Static Load (kips)	Dynamic Load (kips)	Restraint Deflection (in.)	Clearance (in.)	Remarks
1	1 5/8	2	193	973	2.93	0.75	Circumferential break
1	1 5/8	2	188	840	2.34	0.65	Circumferential break
2	1 5/8	2	657	1033	3.21	0.75	Longitudinal break
3	1 5/8	2	672	918	2.68	0.75	Longitudinal break

TABLE 5.2-5 (SHEET 1 OF 2)

SUMMARY OF ANALYSES
PIPE BREAK THAT COULD IMPACT CONTAINMENT WALL

Cash	Line	Nominal Diameter (in.)	Elevation	Aziumth	Drywell Shell Thickness (in.)	Missile Travel (ft)	Impactive Energy (ft-lb)	Performations BRL Formula (in.)	Total Plate Thickness Provided
1	Main steam	24	193 ft - 197 ft	57° - 87° 93° - 123° 237° - 267° 273° - 303°	1/4	1.50	516,979	0.39969	Note 1
2	Main steam	24	148 ft 6 in. - 152 ft 6 in.	30° - 100° 260° - 330°	3/4	10.00	3,791,320	1.50878	2 1/2
3	Main steam	24	158 ft 6 in. - 162 ft 6 in.	30° - 60° 300° - 330°	3/4	13.00	4,939,799	1.79987	2 1/2
4	Main steam	24	161 ft 0 in. - 163 ft 2 in.	20° - 50° 310° - 340°	3/4	15.00	5,372,969	1.90362	2 1/2
5	Feedwater	12	148 ft 6 in. - 152 ft 6 in.	20° - 50° 310° - 340°	3/4	6.00	694,071	0.94287	2 1/2
6	Feedwater	12	148 ft 6 in. - 152 ft 6 in.	80° - 120° 250° - 280°	3/4	7.00	798,345	1.06802	2
7	Feedwater	12	155 ft 0 in .- 160 ft 0 in.	10° - 50° 310° - 350°	3/4	8.00	890,748	1.14893	2
8	RHR discharge	24	139 ft 0 in. - 143 ft 0 in.	90° - 150° 230° - 270°	3/4	3.50	1,905,689	0.95380	2
9	RHR suction	20	156 ft 0 in. - 160 ft 0 in.	180° - 200°	3/4	2.00	619,894	0.54134	Note 1
10	Core spray	10	179 ft 0 in. - 183 ft 0 in.	80° - 100° 260° - 280°	3/4	2.33	178,109	0.47	Note 1

TABLE 5.2-5 (SHEET 2 OF 2)

Cash	Line	Nominal Diameter (in.)	Elevation	Aziumth	Drywell Shell Thickness (in.)	Missile Travel (ft)	Impactive Energy (ft-lb)	Performations BRL Formula (in.)	Total Plate Thickness Provided
11	HPCI	10	163 ft 0 in. - 167 ft 0 in.	110° - 160°	2 9/16	2.0	166,072	0.44993	Note 1
12	HPCI	10	142 ft 0 in. - 146 ft 0 in.	140° - 170°	3/4	6.0	474,834	0.90641	2 1/2
13	RCIC	4	154 ft 0 in. - 156 ft 0 in.	340° - 350°	3/4	2.0	26,611	0.33184	(a)
14	RCIC	4	154 ft 0 in. - 156 ft 0 in.	5° - 25°F	3/4	15.0	200,892	1.27709	2

NOTE:

1. Protection plate is not required, since the drywell plate has adequate thickness to withstand impact.

TABLE 5.2-6

Deleted.

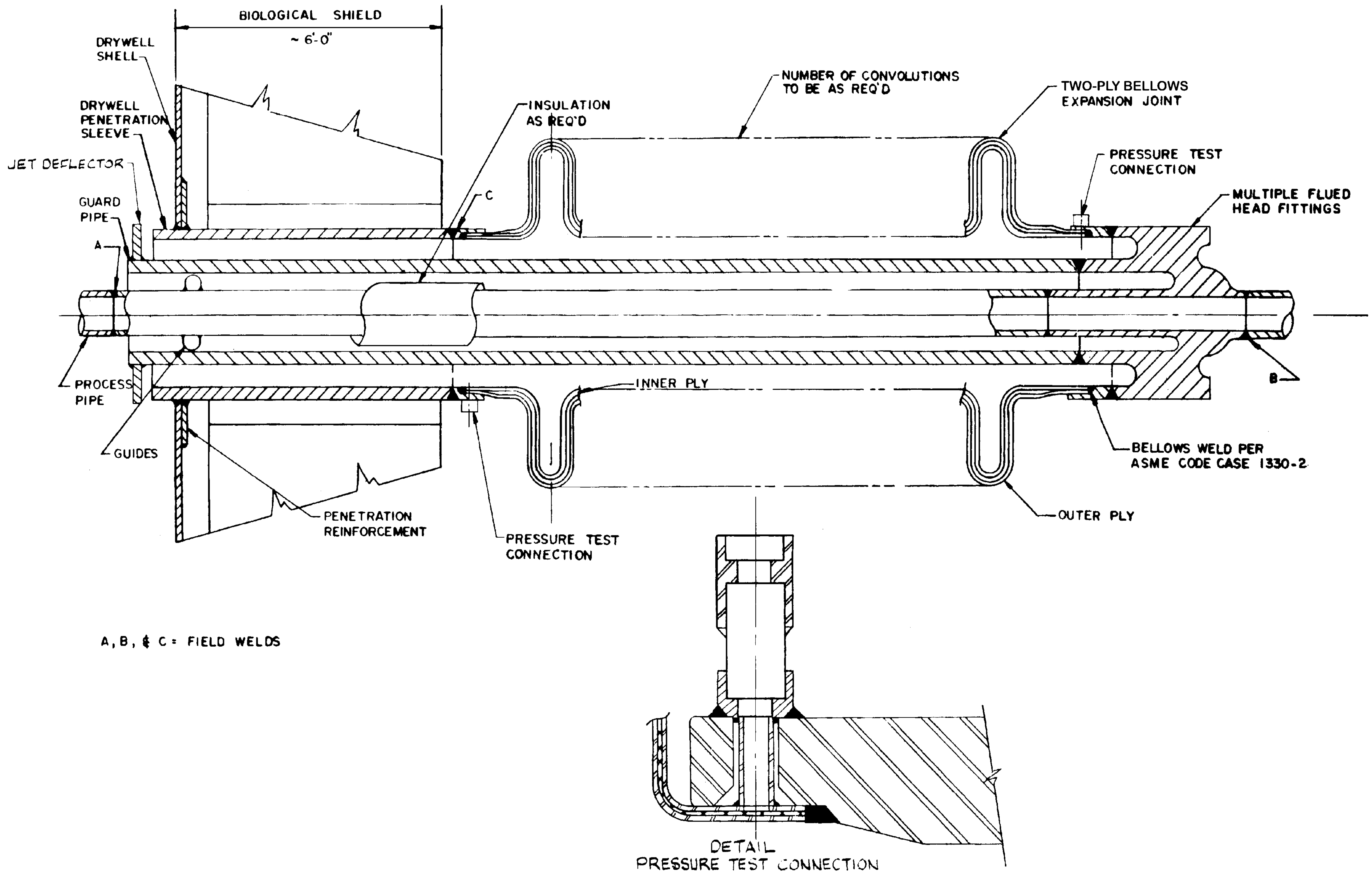
TABLE 5.2-7

PRIMARY CONTAINMENT SYSTEM DESIGN PARAMETERS

General Information

Design Pressure	
Internal - drywell	56.0 psig
- suppression chamber	56.0 psig
External - drywell	2.0 psig
- suppression chamber	2.0 psig
Design Temperature	
Drywell	281°F
Suppression chamber	281°F
Free Volume	
Drywell (including vent system)	146,010 ft^3
Suppression chamber	
- approximate minimum	112,900 ft^3
- approximate maximum	115,900 ft^3
Leakage Rate	1.2% free vol/day
Downcomer Submergence	4 ft 0 in.[(a)(b)]
Overall Vent Resistance Loss Factor	4.4[(c)], (5.51)[(a)(b)]
Pool Depth (Normal)	12 ft 4 in.
No. of Vents	8
Normal Vent Diameter (ID)	5 ft 11 in.
Total Vent Area	220 ft^2
No. of Downcomers	80
Nominal Downcomer Diameter	2.0 ft

a. Value is based upon Mark I Long-Term Containment Program modifications and operation in the EOD.
b. Value is based upon the analysis for an RTP of 2804 MWt.
c. Value is based upon original LOCA analysis.



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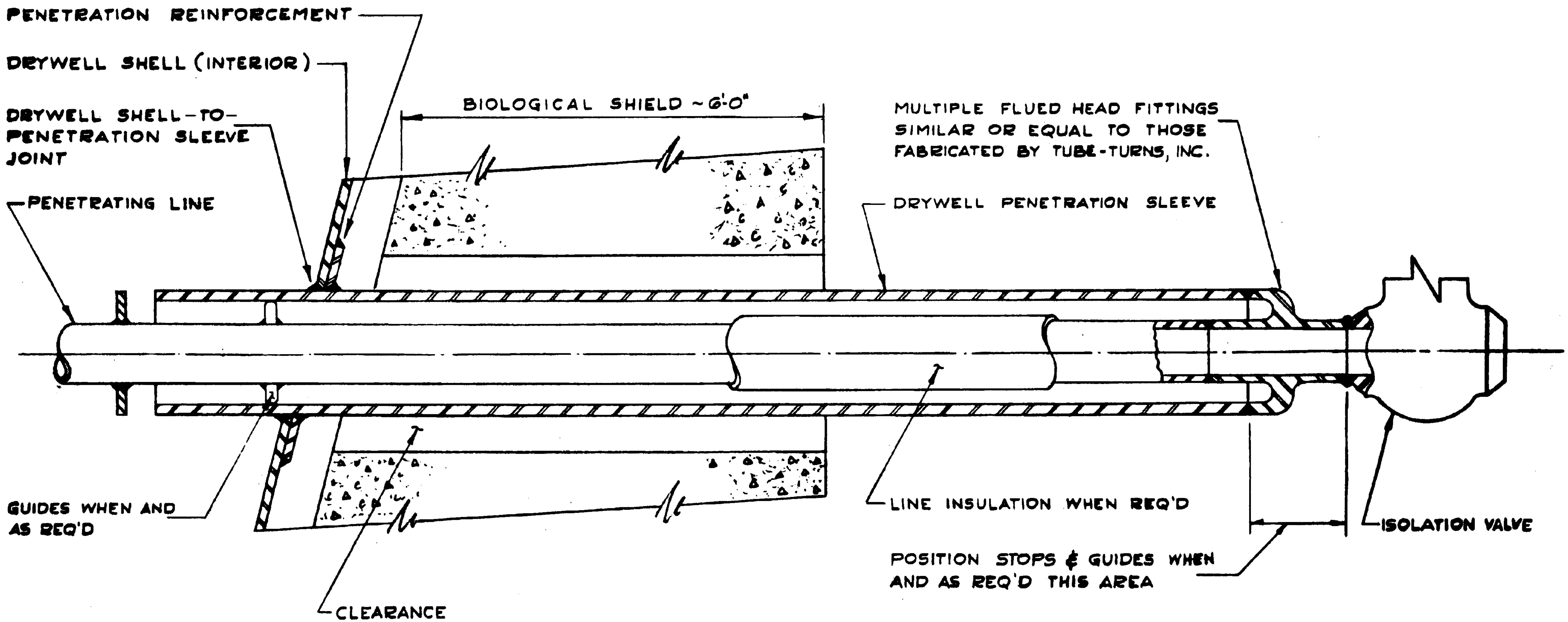
PIPE PENETRATIONS – TYPE 1 – ACCOMMODATE THERMAL MOVEMENTS

FIGURE 5.2-1



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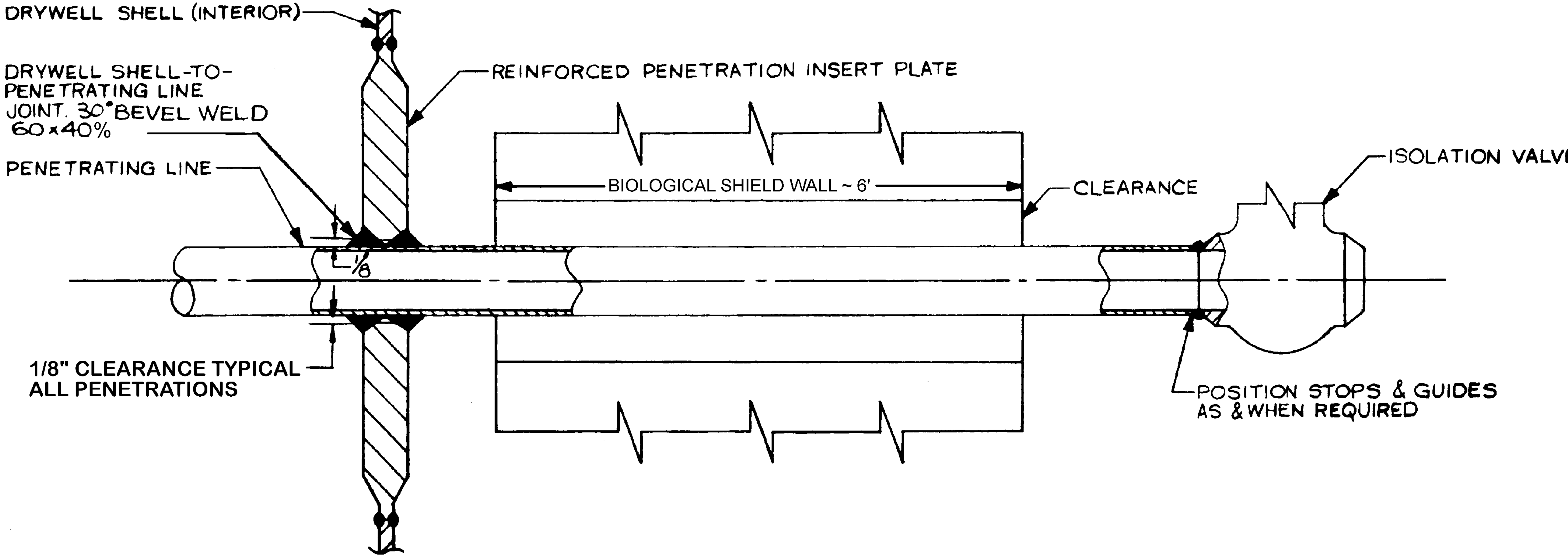
PIPE PENETRATIONS – TYPE 2.1 – THERMAL MOVEMENTS RELATIVELY SMALL

FIGURE 5.2-2



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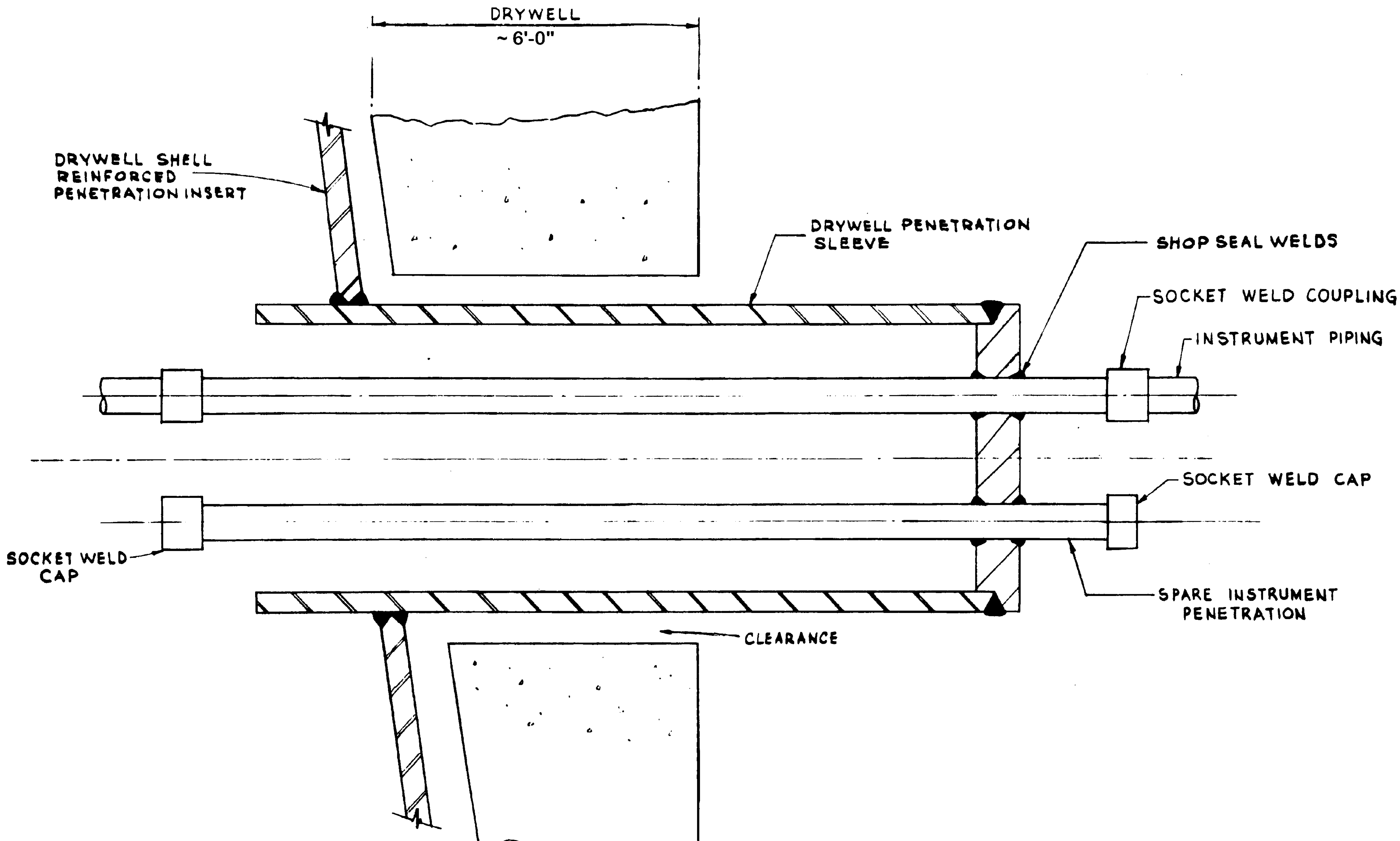
PIPE PENETRATIONS – TYPE 2.2 – THERMAL MOVEMENTS RELATIVELY SMALL

FIGURE 5.2-3



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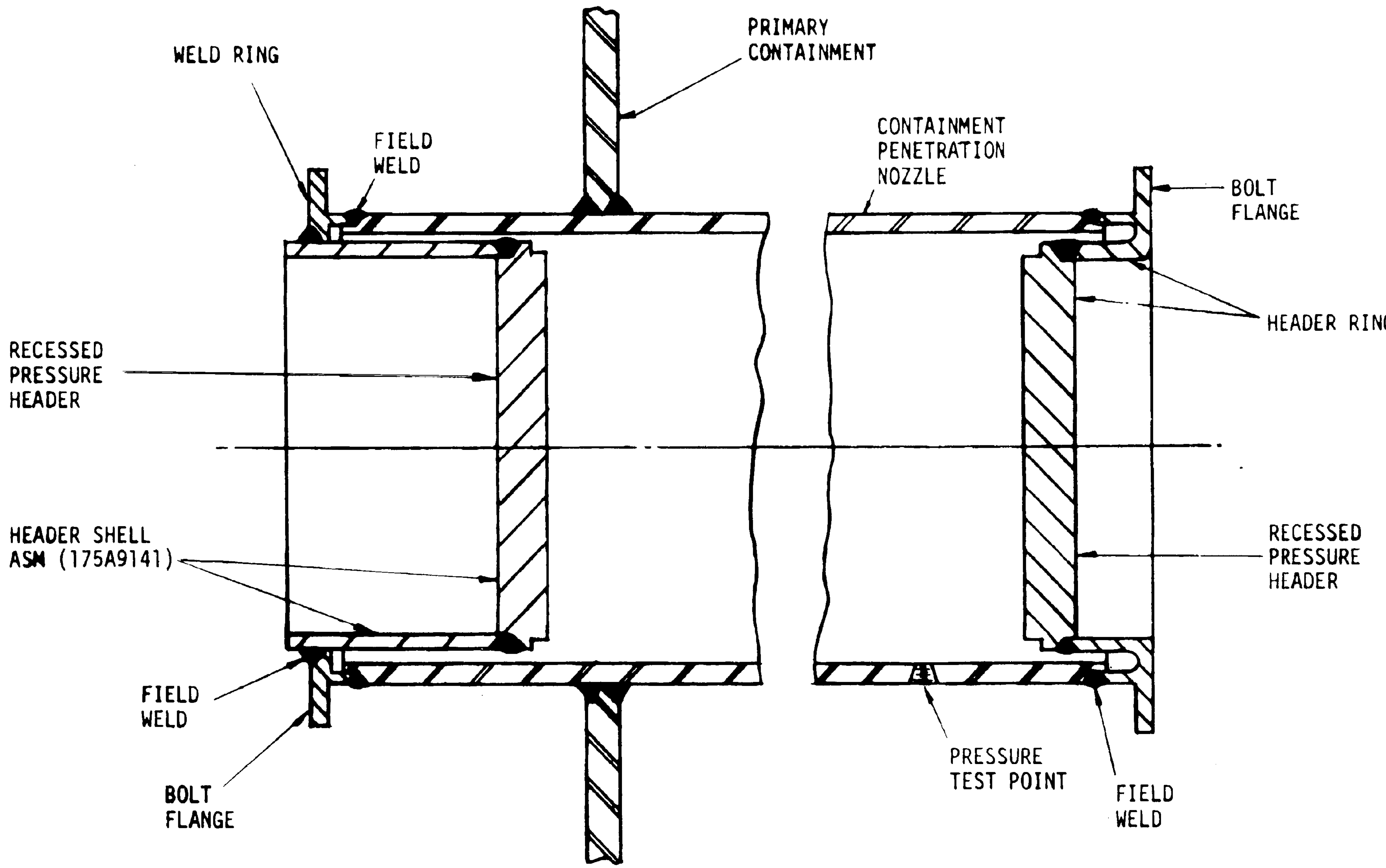
TYPICAL INSTRUMENT PENETRATION

FIGURE 5.2-4



ELECTRICAL PENETRATION ASSEMBLY STRUCTURAL COMPONENTS

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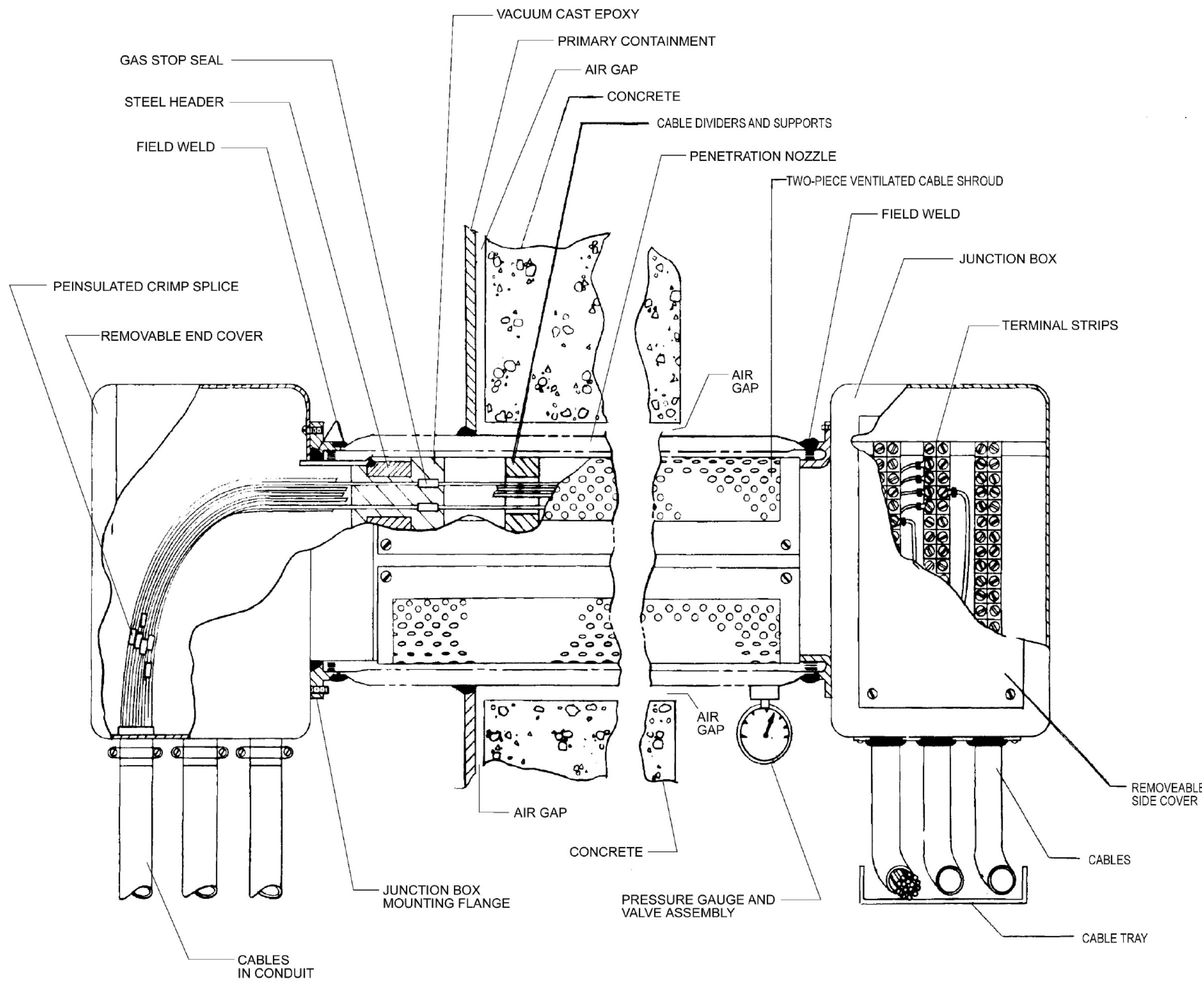
TYPICAL ELECTRICAL PENETRATION
STRUCTURAL COMPONENTS

FIGURE 5.2-5



INSTALLED ELECTRICAL PENETRATION ASSEMBLY

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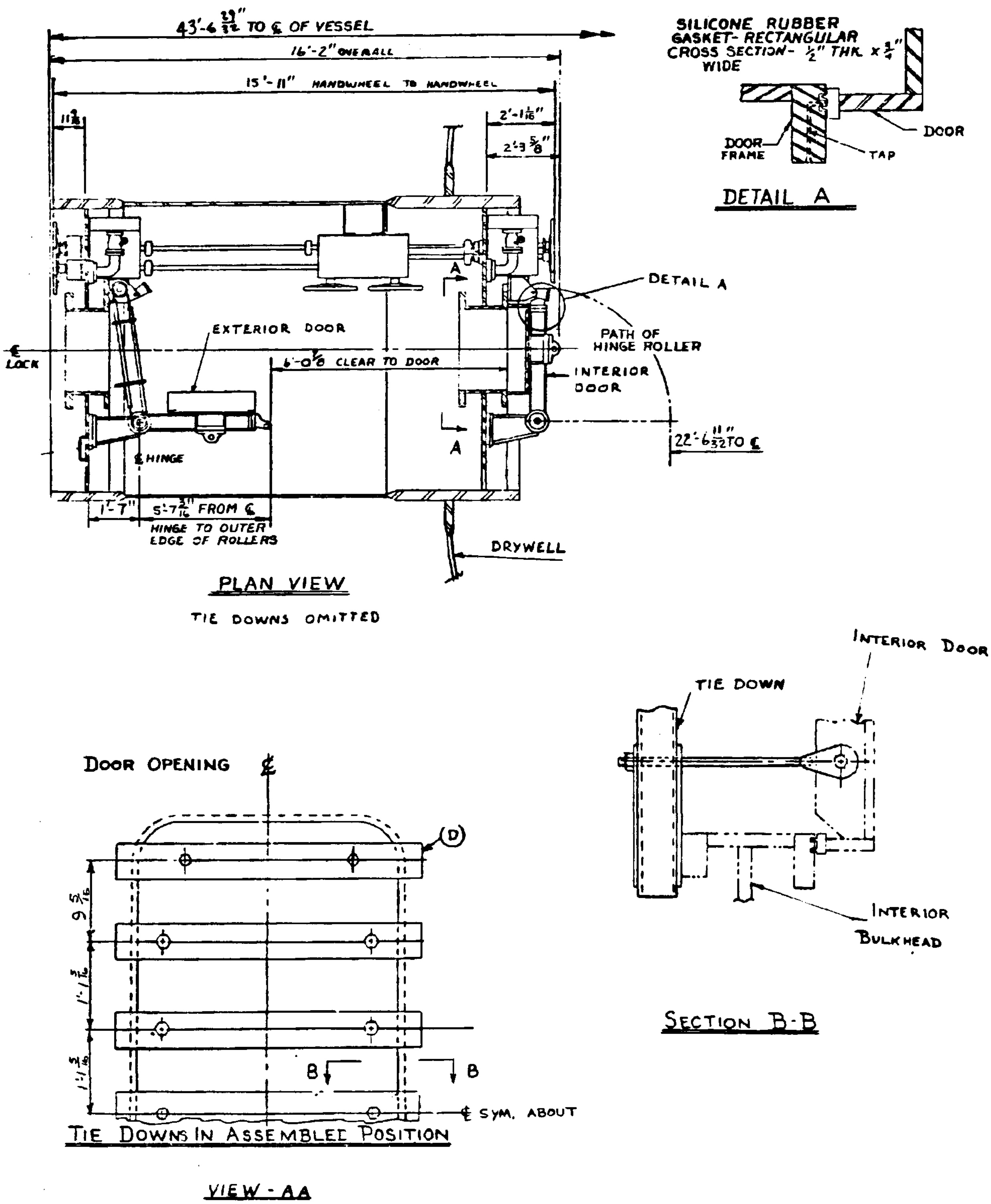
TYPICAL ELECTRICAL PENETRATION ASSEMBLY DETAIL

FIGURE 5.2-6



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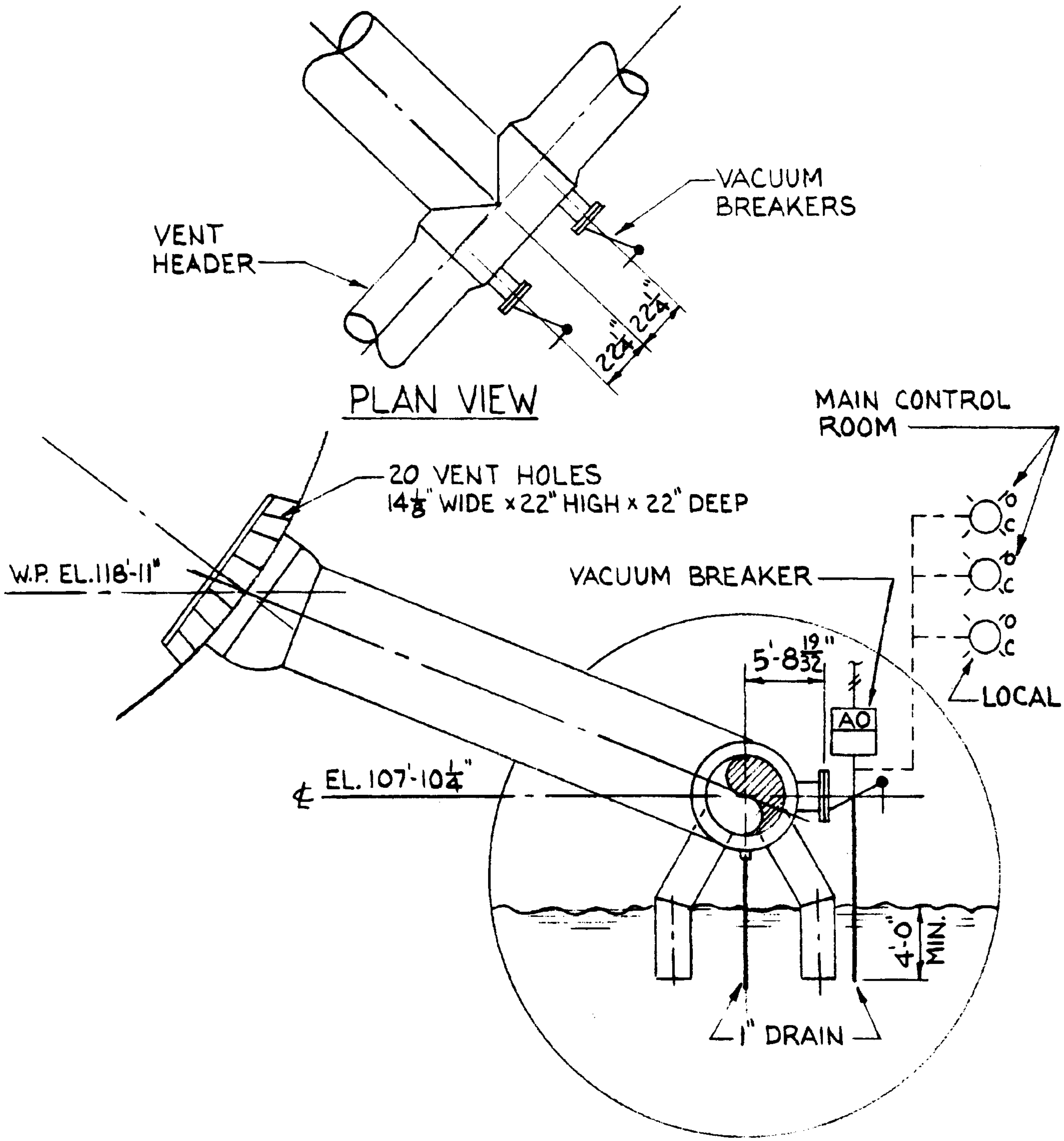
DETAILS OF CONTAINMENT AIRLOCK

FIGURE 5.2-7



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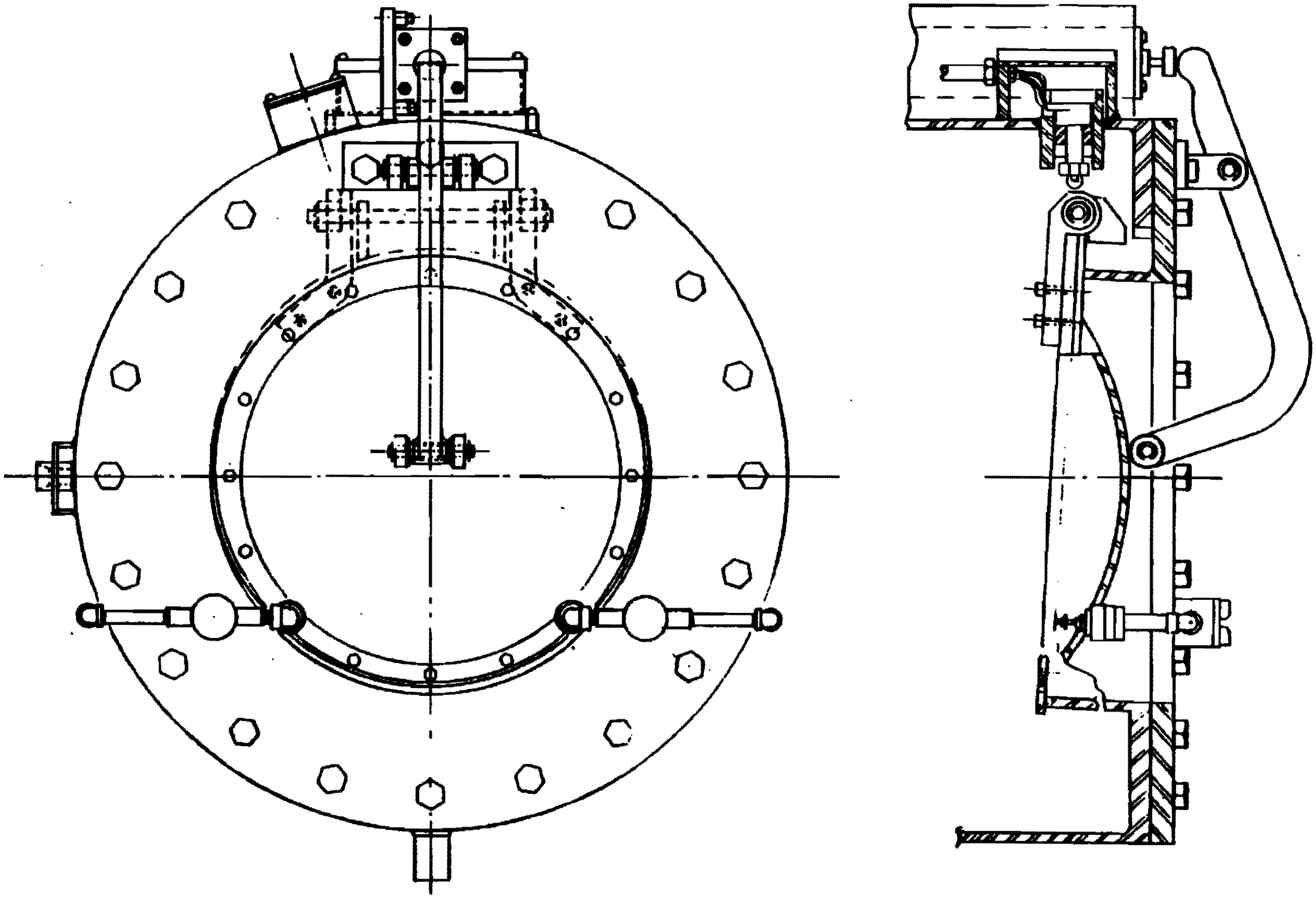
SUPPRESSION CHAMBER-TO-DRYWELL
VACUUM BREAKER TYPICAL LOCATION

FIGURE 5.2-8



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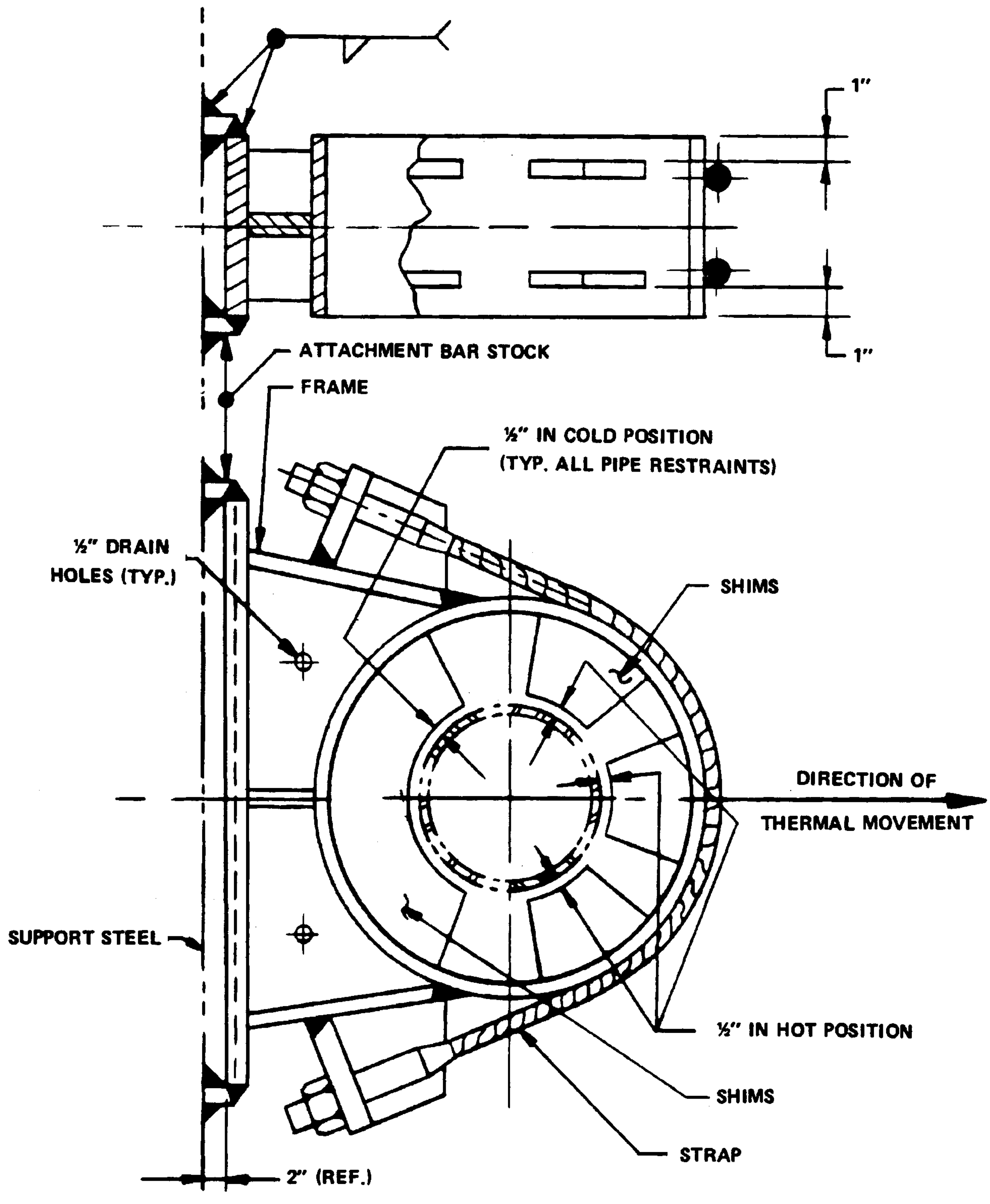
SUPPRESSION CHAMBER-TO-DRYWELL VACUUM BREAKER DETAILS

FIGURE 5.2-9



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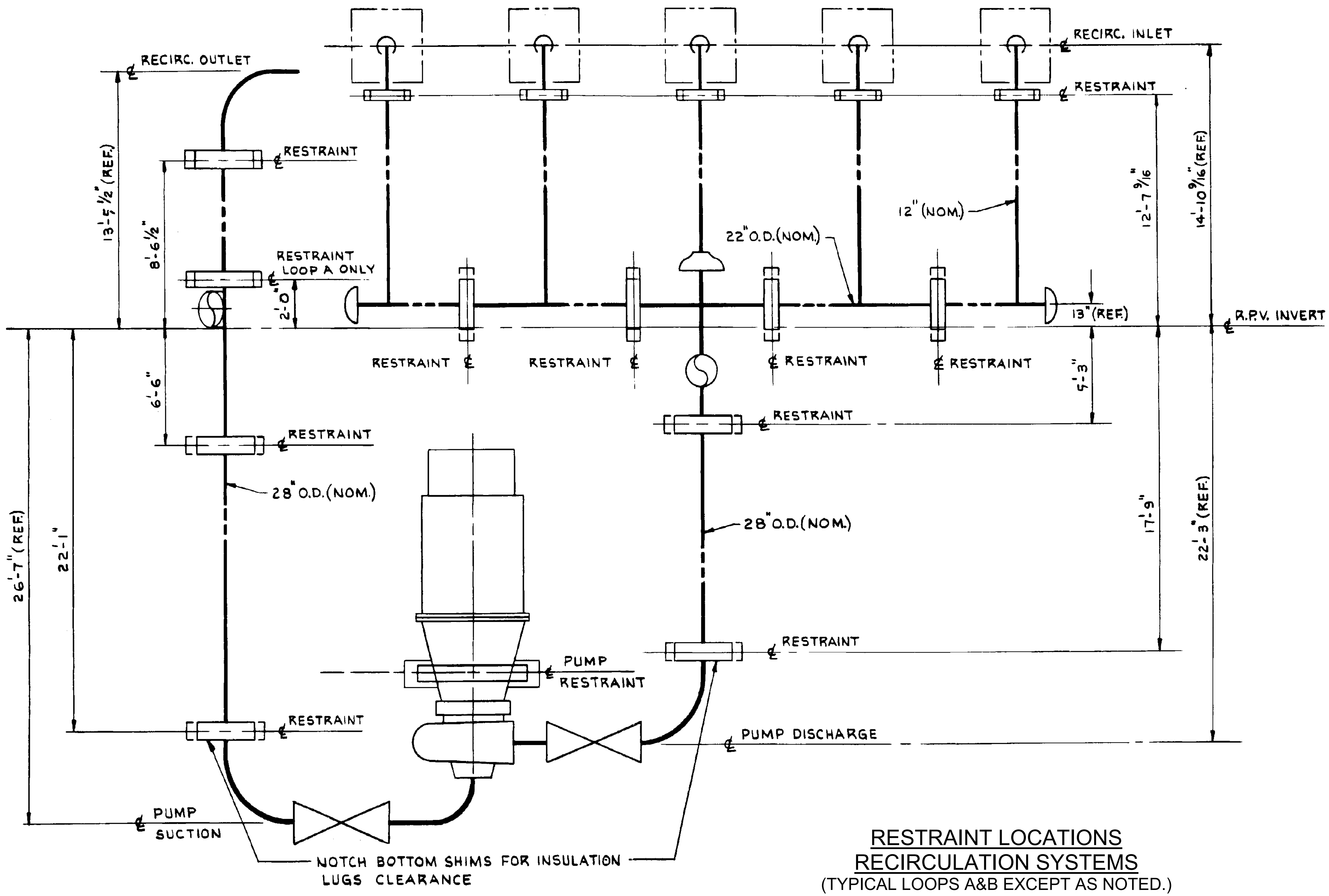
TYPICAL PIPE WHIP RESTRAINT
RECIRCULATION SYSTEM

FIGURE 5.2-10



RESTRAINT LOCATIONS
RECIRCULATION SYSTEMS
(TYPICAL LOOPS A&B EXCEPT AS NOTED.)

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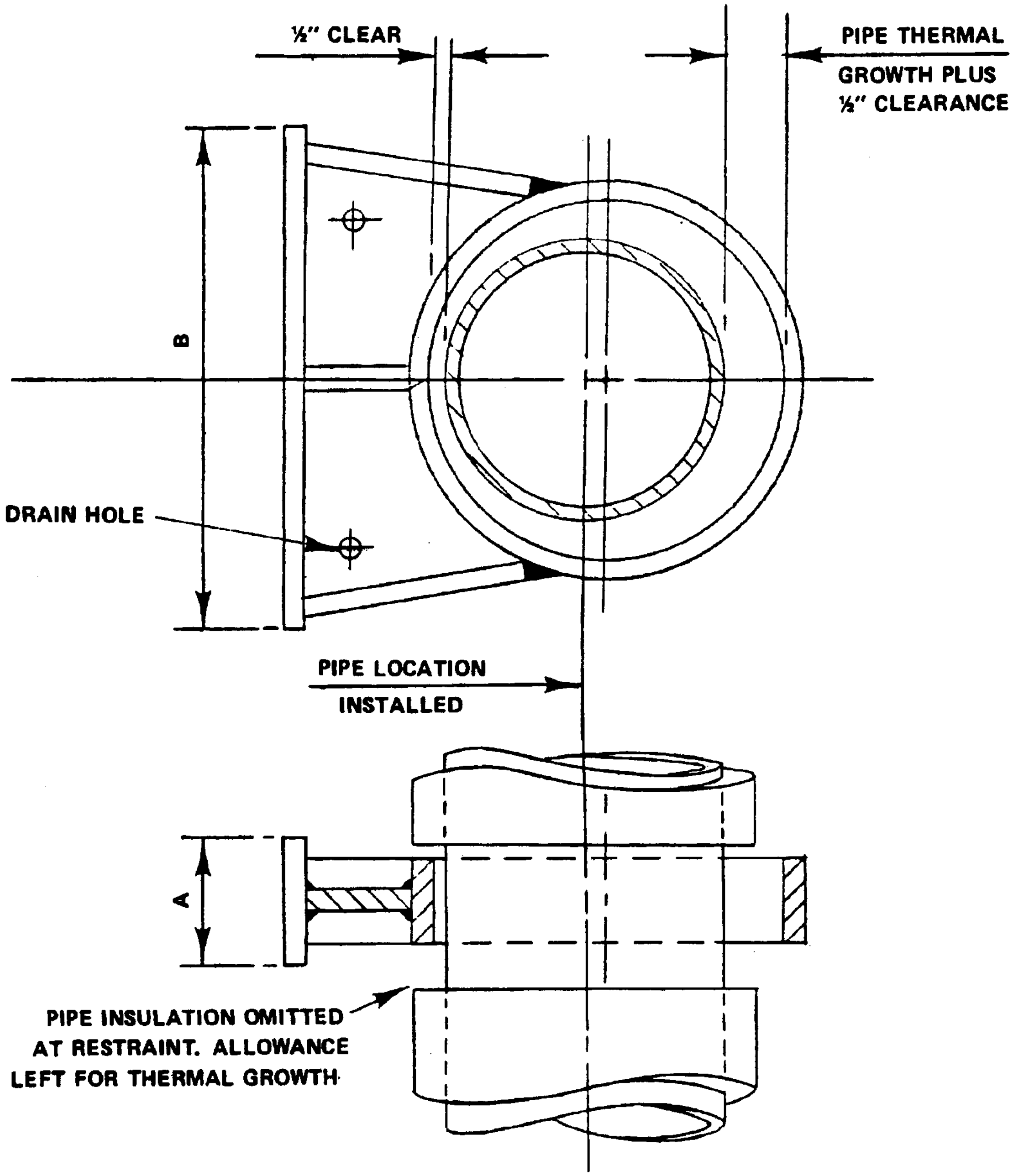
RESTRAINT LOCATIONS
RECIRCULATION SYSTEM

FIGURE 5.2-11



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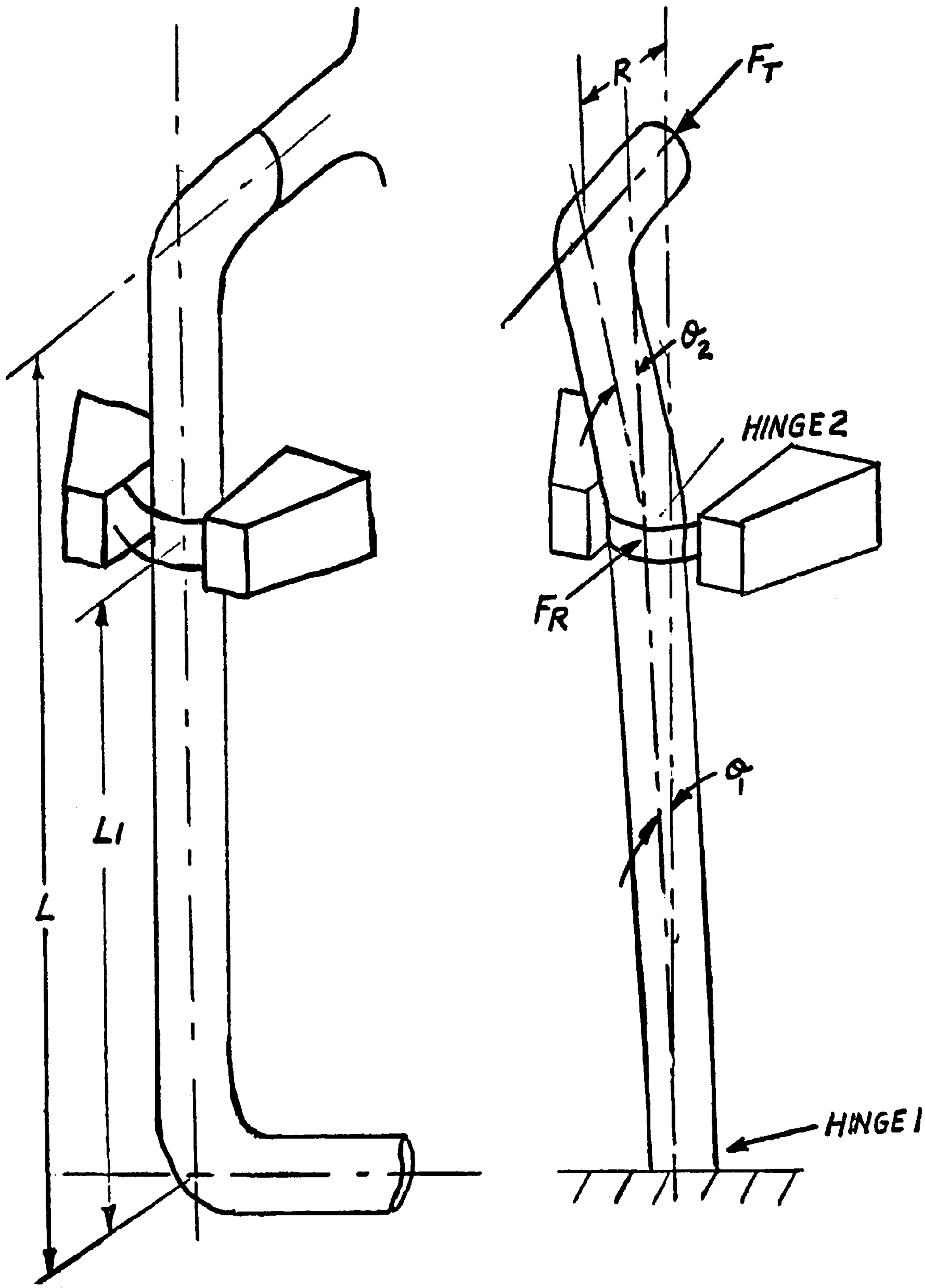
TYPICAL RESTRAINT
MAIN STEAM AND FEEDWATER LINES

FIGURE 5.2-12



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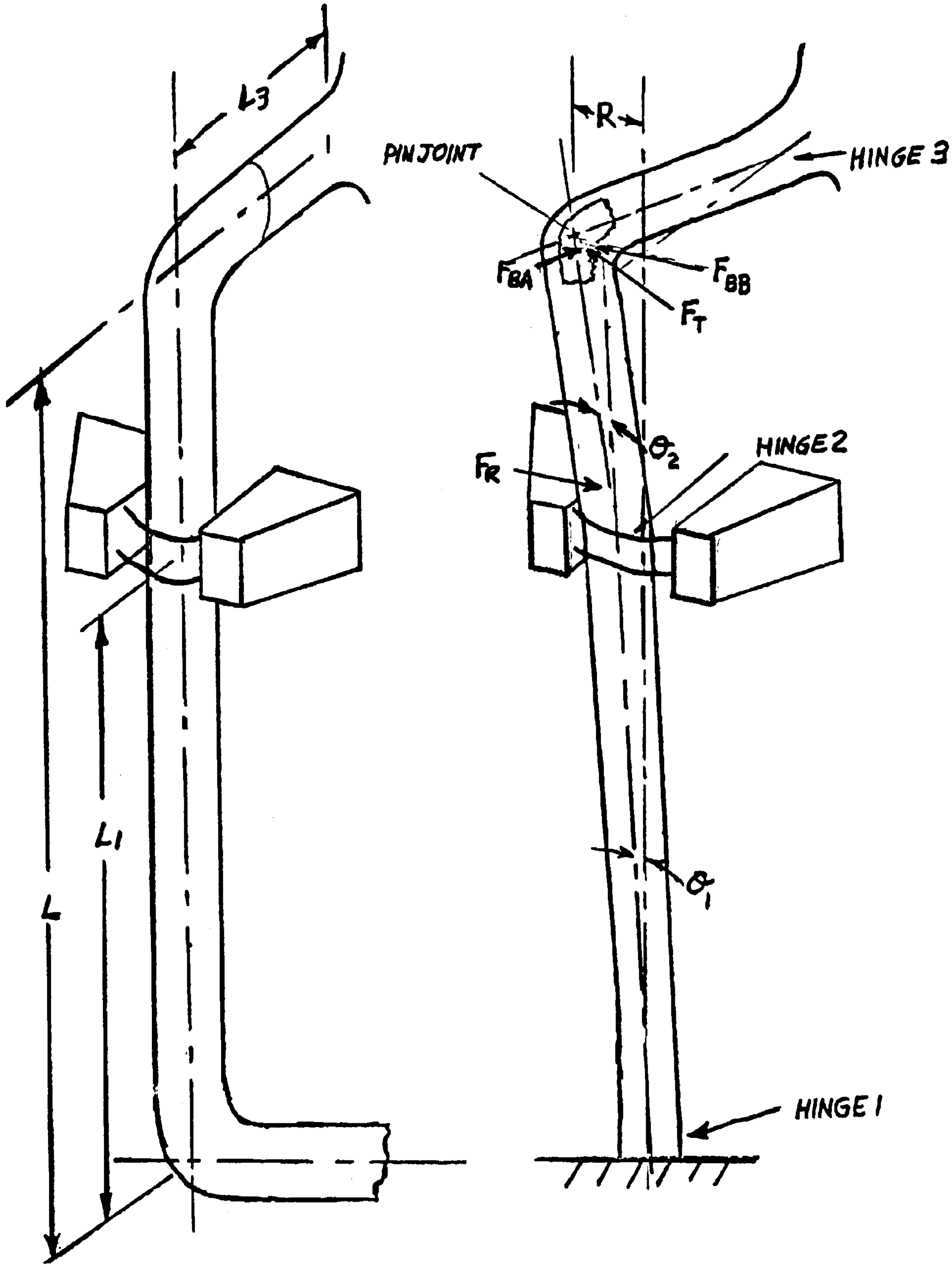
CIRCUMFERENTIAL BREAK MODEL

FIGURE 5.2-13



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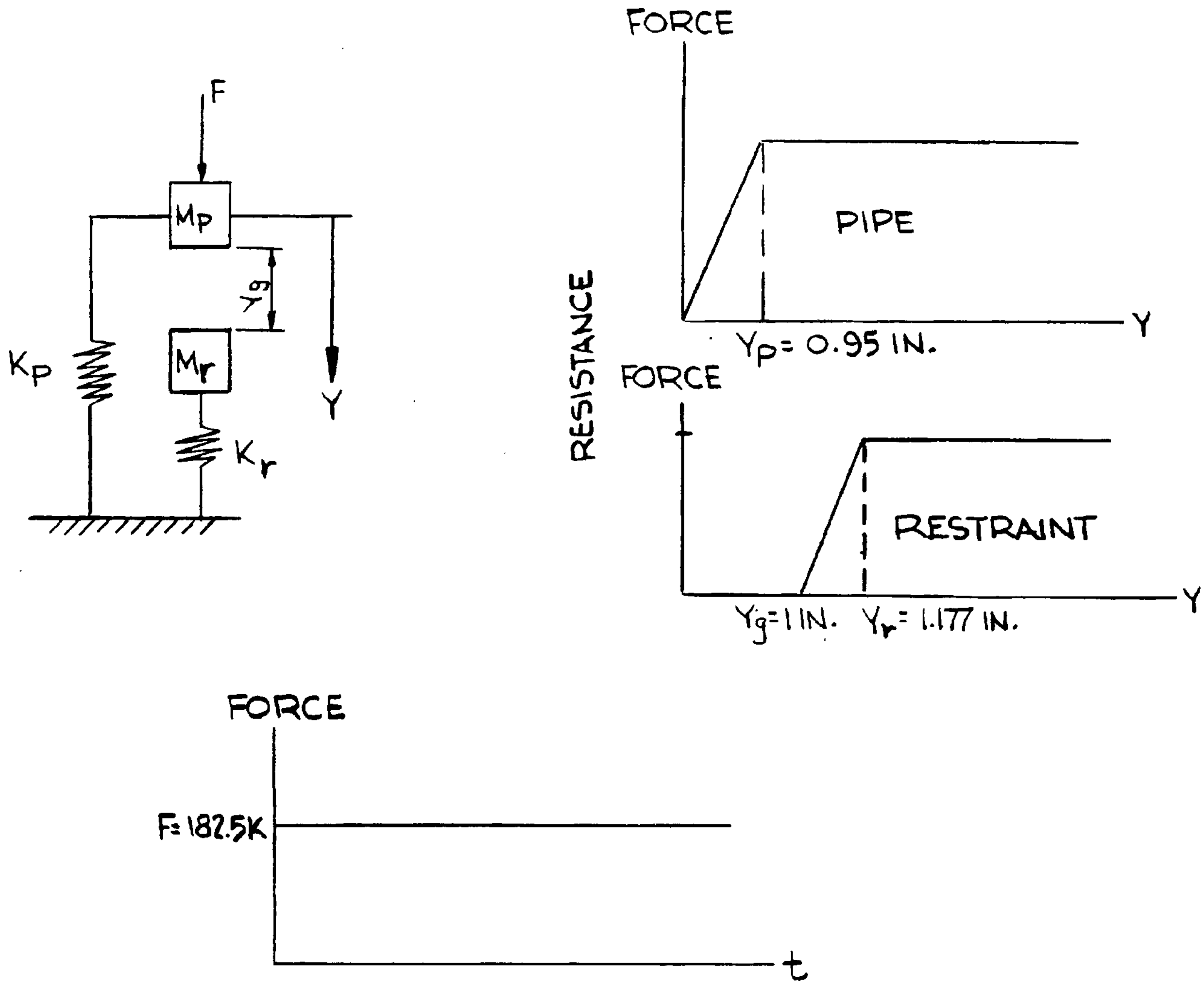
LONGITUDINAL BREAK MODEL

FIGURE 5.2-14



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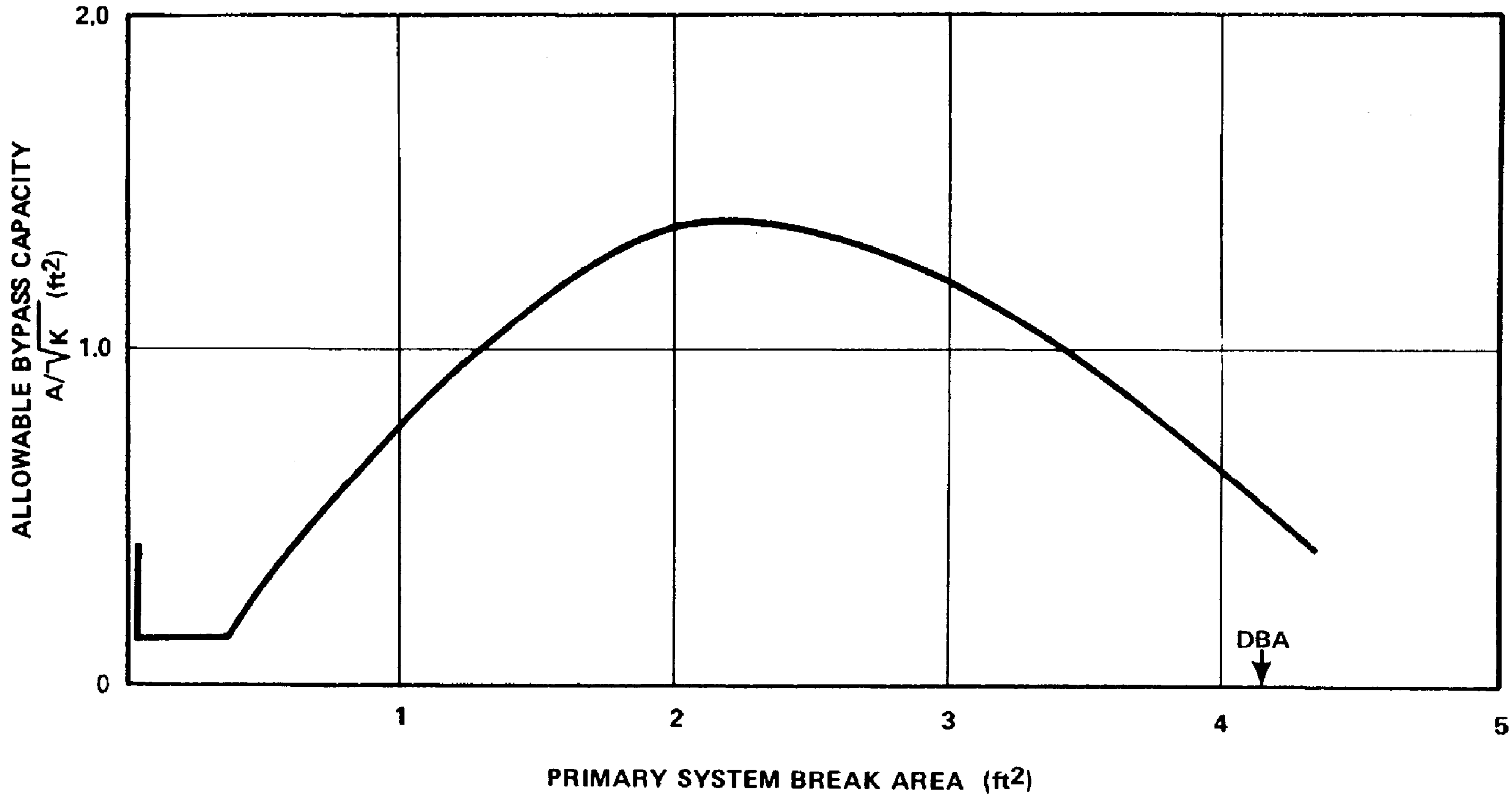
MATHEMATICAL MODEL, FORCING FUNCTION
LOAD DEFORMATION PROPERTIES OF
PIPE AND RESTRAINT

FIGURE 5.2-15



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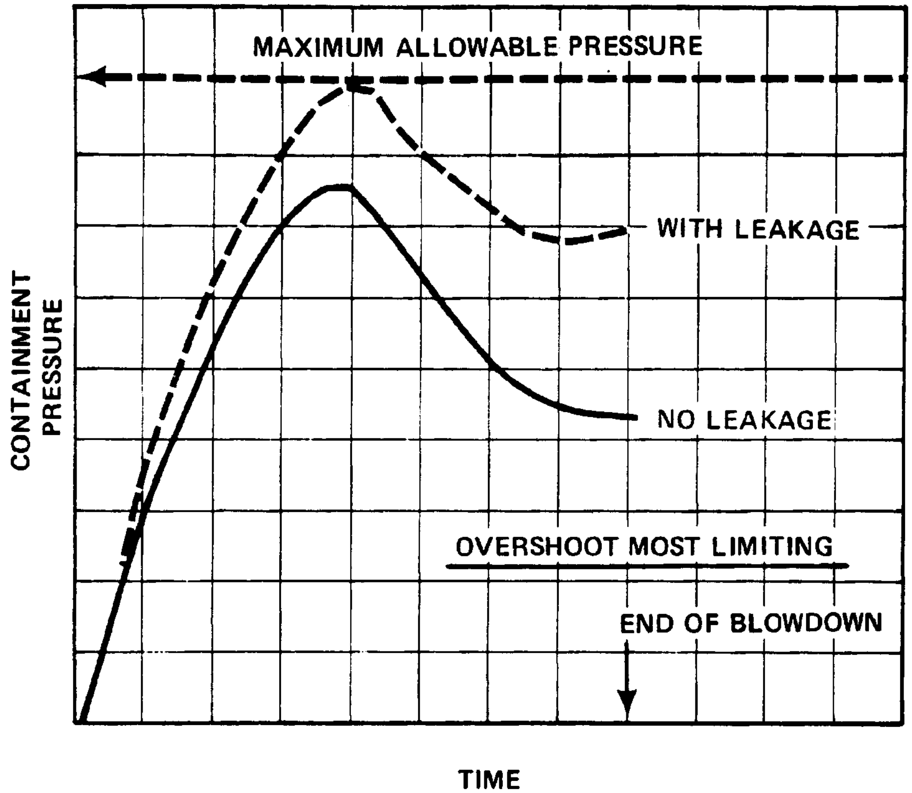
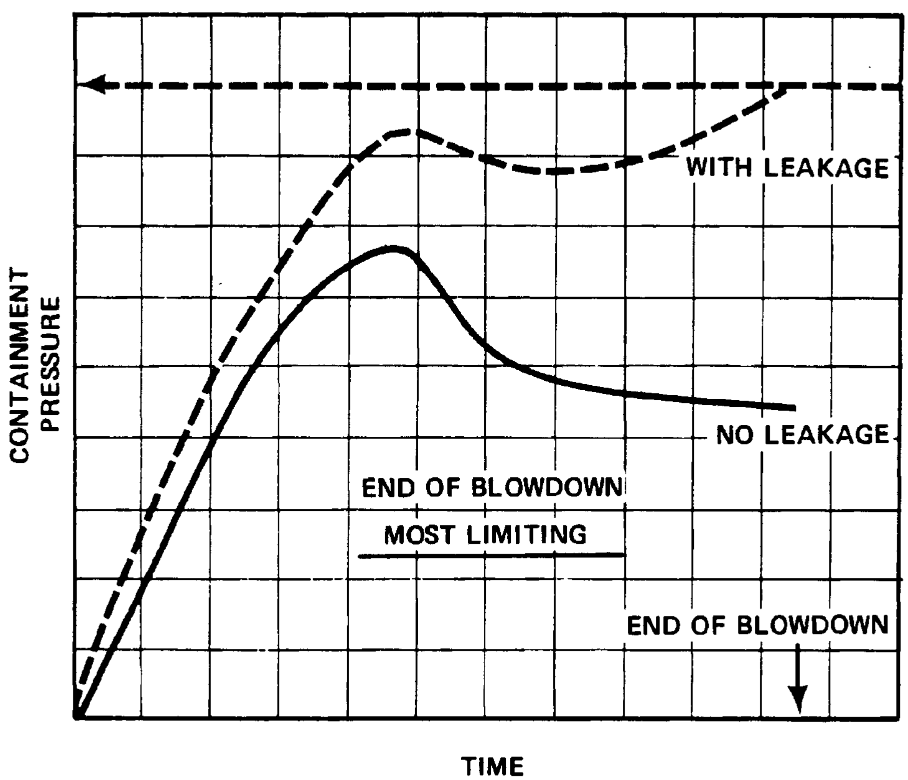
ALLOWABLE PRESSURE SUPPRESSION BYPASS LEAKAGE CAPACITY AS FUNCTION OF PRIMARY SYSTEM BREAK AREA

FIGURE 5.2-16





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SCHEMATIC DIAGRAM SHOWING HOW OVERSHOOT OR END OF BLOWDOWN MAY BE CONDITION MOST LIMITING LEAKAGE

FIGURE 5.2-17

THIS FIGURE HAS BEEN DELETED.

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SOUTHERN COMPANY SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	MAXIMUM NITROGEN REQUIRED FOR DILUTION – AEC SAFETY GUIDE 7 ASSUMPTIONS – NO CONTAINMENT LEAKAGE FIGURE 5.2-18

5.3 SECONDARY CONTAINMENT SYSTEM

5.3.1 SAFETY DESIGN BASES

The secondary containment system is designed to:

A. Provide secondary containment when the primary containment is closed and in service, and primary containment when the primary containment is open; e.g., during refueling.

B. Limit the ground-level release of airborne radioactive material and provide a means for a controlled elevated release of the building atmosphere so that offsite doses from a fuel-handling or loss-of-coolant accident (LOCA) will be below the guideline values stated in 10 CFR 50.67.

5.3.2 DESCRIPTION

5.3.2.1 General

The secondary containment system consists of following three subsystems:

- Reactor building.
- Standby gas treatment system (SGTS).
- Main stack.

The secondary containment system surrounds the primary containment system and is designed to provide secondary containment for the postulated LOCA. The secondary containment system also surrounds the refueling facilities and is designed to provide primary containment for the postulated fuel-handling accident.

The secondary containment encompasses the following three separate zones:

- HNP-1 reactor building (Zone 1).
- HNP-2 reactor building (Zone 2).
- Common refueling floor (Zone 3).

The secondary containment boundary required to be operable is dependent upon the operating status of both units, as well as the configuration of doors, hatches, refueling floor plugs, secondary containment isolation valves, and available flowpaths to the SGTS. During refueling activities, SGTS suction from the reactor building below the refueling floor, and the torus and drywell area is isolated by gagging closed certain valves in the reactor building suction lines to achieve modified secondary containment. The gagged-closed valves are controlled by plant administrative programs.

The secondary containment system utilizes four different features to mitigate the consequences of a postulated LOCA (pipe break inside the drywell) and the fuel-handling accident as follows:

- Negative pressure barrier that minimizes the ground-level release of fission products by exfiltration.
- Low-leakage containment volume that provides a holdup time for fission product decay prior to release.
- Removal of particulates and iodines by filtration prior to release.
- Exhausting of the secondary containment atmosphere at an elevated release point that aids in dispersion of the effluent by atmospheric diffusion.

A different combination of subsystems provides each of the above features as follows:

- Reactor building, reactor building isolation, and SGTS exhaust fans.
- Reactor building.
- SGTS filters.
- Main stack.

5.3.2.2 Reactor Building

The reactor building completely encloses the reactor and its pressure-suppression primary containment system. The reactor building houses the following:

- Refueling and reactor servicing equipment.
- New and wet spent-fuel storage facilities.
- Other reactor auxiliary and service equipment.
- Emergency core cooling system.
- Reactor water cleanup demineralizers.
- Standby liquid control system.
- Control rod drive system.
- Reactor protection system.

- Electrical equipment components.

The building is designed for minimum leakage so that the SGTS has the necessary capacity to reduce and hold the building at a subatmospheric pressure under normal wind conditions.

The reactor building structural design, Class I design requirements, and shielding requirements are discussed in detail in chapter 12.

Penetrations of the secondary containment system are designed to have leakage characteristics consistent with secondary containment leakage requirements. Figure 5.3-1 illustrates the piping penetration through the reactor building walls for the following safety-related piping:

- SGTS discharge to main stack.
- Residual heat removal service water inlet and outlet.
- Plant service water inlet.
- Condensate storage tank to high-pressure coolant injection.

Electrical penetrations in the reactor building are designed to withstand normal environmental conditions and retain their integrity during the postulated fuel-handling accident and the loss-of-coolant accident inside the drywell.

Duct penetrations of the secondary containment system are provided with two isolation dampers in series. Both dampers fail close upon loss of ac power to the solenoids or upon loss of instrument air to the dampers. The isolation dampers isolate the secondary containment upon receipt of an isolation signal. The dampers are designed to have low-leakage characteristics.

5.3.2.3 Standby Gas Treatment System

The SGTS (drawing nos. H-16020 and H-16174) provides a means for minimizing the release of radioactive material from the containment to the environs by filtering and exhausting the atmosphere from the reactor building. Drywell and torus purge and vent exhausts are directed to the SGTS for processing prior to release. For all cases, elevated release is ensured by exhausting to the main stack.

The effectiveness of a single train will not be altered by loss of the redundant train with its dampers failed open. A backdraft damper at the discharge of each fan prevents back flow through the redundant train. In addition, the flow through the bypass line is restricted so as not to impair the integrity of the operable train in the unlikely event damage to the bypass line occurs coincident with the accident.

The basic system consists of two identical parallel air filtration assemblies (trains) separated by a 42-in.-thick concrete wall and enclosed within a Seismic Class 1 structure. The 18-in.

underground discharge pipe leading to the main stack is Seismic Class 1. Each train is full capacity and consists of the following components in the direction of airflow:

- Demister or moisture separator.
- Electrical heating coil. (Note: The heater operation is not credited and is maintained for defense-in-depth.)
- Prefilter.
- High-efficiency particulate air (HEPA) filter.
- Charcoal adsorber.
- Second charcoal adsorber.
- Final HEPA filter.
- Exhaust fan.

The total free volume of the secondary containment system is ~ 2 x 10^6 ft^3, and the portion of the volume above the refueling floor is 725,000 ft^3. Based upon the secondary containment system free volume, each SGTS train has the capability equal to two air volume changes per day (assuming no wind).

An analysis of the effects of windspeed on the leakage characteristics of the secondary containment system concluded there will be slight or no exfiltration from the secondary containment system at windspeeds up to 65 mph. It is highly improbable these high windspeeds would occur coincident with the accident.

Each filter train has a design flowrate of 3000 to 4000 ft^3/min. With the reactor building isolated, two SGTS filter trains (one of which may be an HNP-2 filter train) have the necessary capacity to reduce and hold the building at a subatmospheric pressure under neutral wind conditions.

The SGTS fan characteristics indicate the maximum capability of the fan at the shutoff point is ~ 16-in. water gauge (wg). However, it is very unlikely the fan can develop the 16-in. wg pressure due to the inherent fan design and system characteristics.

Adequate openings in the interior walls and floor slabs in the reactor building; e.g., around pipe sleeves, duct penetrations, limit the pressure differential between the subcompartments to negligible values. The external walls of the reactor building, the refueling floor, and roof slab are all designed to withstand pressures exceeding 95 lb/ft^2 or 18-in. wg at normal working stresses. In addition, a high pressure differential between the inside and outside of the reactor building, at locations above and below the refueling floor, is alarmed in the main control room (MCR).

Any accident condition in either HNP-1 or HNP-2 (HNP-1 or HNP-2 LOCA, HNP-1 or HNP-2 reactor building high radiation, or HNP-1 or HNP-2 refueling floor high radiation) starts both trains of the HNP-1 and HNP-2 SGTSs. This design feature allows more SGTS capacity to be available for draw down of all essential areas in both units to a subatmospheric pressure in order to contain the product of the radiological accident. The number and combinations of SGTS trains required to draw down the various secondary containment types are given in the Technical Requirements Manual. The two trains of the HNP-1 SGTS can be manually operated from the MCR.

The design features for the HNP-1 and HNP-2 SGTSs are somewhat different. The discharge lines from the HNP-1 trains tie together into an 18-in. header for discharge into the main stack. The HNP-2 trains have separate 18-in. headers for discharge into the main stack. Unlike the HNP-2 SGTS, the HNP-1 SGTS is designed with a timer logic such that trains A and B are set to trip at ~ 6 and 4 min, respectively, from initial start on sensing low airflow conditions. This design feature allows both trains to keep operating for ~ 4 min, regardless of the low airflow status of any particular train. A train that fails due to a low-flow condition is tripped, and is automatically reset and placed in the standby condition. The standby train automatically starts on a low airflow condition in the operating train.

Isolation valves fail open upon loss of instrument air to the air operators on the valves. The operation of all power-operated active components is indicated, and the failure of the system to perform satisfactorily is annunciated in the MCR.

The demister or moisture separator is designed to remove entrained water droplets and mist from the entering air stream.

The second component designed for humidity control is the 15-kW electrical heating coil designed to reduce the relative humidity of the entering air stream. The heater operation is not credited and is used for defense-in-depth. The fans, heating coils, and controls are powered from the emergency service portions of the auxiliary power distribution system. An interlock with its associated exhaust fan prevents the heating coil from operating when the fan is shut down. The interlock feature permits operation of the heater whenever the fan is activated.

The third element of the filter train is the prefilter designed to remove large particulates and protect the HEPA filter. The prefilter has an efficiency of 85% based upon the ASHRAE 52-76 test standard.

The HEPA filters are designed for 99.95% efficiency in removing a monodispersed aerosol of dioctyl phthalate (DOP) droplets having a light scattering mean diameter of ~ 0.3 mm. Each HEPA unit is composed of a waterproof, fire-retardant, glass fiber media built into an integral frame. At each HEPA location in the train, four individual HEPA filters are stacked in a two-by-two array, facing the airflow. Each filter is designed for 1000-sf^3/min airflow and has standard dimensions of 24 in. x 24 in. x 11 1/2 in. deep. The frame of each element is held against a gasket and a flat plate surface.

The charcoal adsorbers in each train are mounted in dual-tray module drawers. At each charcoal adsorber bank, 12 of these drawers (24 trays) have a nominal rating of 333 sf^3/min. Each tray has dimensions of 24 in. x 26 ½ in. x 2 in. deep. The drawers are separated by ~ 2 in. The total charcoal required per train is 1130 lb.

Each drawer is mounted in a single-unit, stainless steel frame. Vertical airflow through charcoal is as nearly equally distributed across all the trays as possible. The charcoal adsorbers are iodide-impregnated activated carbon with a tested methyl iodide (CH_3) removal efficiency of 97.5% at an entering condition of 30°C, 95% relative humidity in accordance with ASTM D3803-1989.

All train components are composed of fire-resistant materials, and a manual water spray system is provided for each train. Temperature sensors are located in the vicinity of charcoal adsorbers for each train, and abnormal high air temperature is annunciated in the MCR. Additional temperature sensors monitor the air temperature downstream of each charcoal adsorber bank. These temperatures are continuously recorded in the MCR. The fans, including motors, are designed to be operable at an ambient temperature of 150°F. A bypass line is provided for removal of decay heat from fission products deposited on charcoal adsorbers. The additional bank of charcoal adsorbers in each train was added to reduce the release of radioactive material to the environs.

Redundant excess-flow isolation dampers (in series) on the containment purge and vent line, upstream of the SGTS filter trains prevent a high LOCA pressure from overpressurizing the filter trains in the unlikely event a LOCA occurs during containment venting.

In accordance with the requirements of NRC Order EA-13-109, “Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions,” capabilities are provided to vent the torus in the event of a loss of long-term decay heat removal sequence by bypassing the low-pressure SGTS filter trains. This vent capability, as shown on drawing nos. H-16020, H-16024, and H-16174, can be utilized for severe accident situations and is not utilized for normal operation or DBA mitigation.

5.3.2.3.1 Instrumentation

The following instrument systems monitor SGTS operation:

- System outlet radiation monitor (indicated and recorded).
- System outlet flow (recorded).
- Refueling floor versus outside atmosphere differential pressure (recorded).
- Reactor building versus outside atmosphere differential pressure (recorded).
- Filter bed A differential pressure (indicated and recorded).
- Filter bed B differential pressure (indicated and recorded).
- Charcoal filter bed A temperature (recorded).
- Charcoal filter bed B temperature (recorded).

5.3.2.4 Main Stack

The location of the main stack is shown on HNP-2 figure 1.2-4. The top of the stack is at ~ el 513 ft msl.

5.3.2.5 Secondary Containment Bypass Leakage

As part of the implementation of alternative source term (AST) as described in HNP-2-FSAR subsection 15.1.11, potential HNP-1 secondary containment bypass leakage paths have been identified consistent with the HNP-2 licensing basis as described in HNP-2-FSAR paragraph 6.2.1.2.2.1. In addition, a limitation on secondary containment bypass leakage has been added to the HNP-1 Technical Specifications.

The total potential bypass leakage from the lines listed in table 5.3-1 does not exceed 2.0 %/day of the design containment leakage. The resultant offsite radiological consequences of the design basis LOCA do not exceed the limits specified in 10 CFR 50.67.

Also part of the implementation of AST, when evaluating main control room doses due to the design basis LOCA, it is conservatively assumed that all the bypass leakage ends up in the main condenser through the following three potential paths listed in table 5.3-1, specifically the HPCI steam line condensate to the main condenser, the RCIC steam line condensate to the main condenser, and the RWC drainage to the main condenser. This assumption is necessary because of the location of the main control room in the HNP-1 and HNP-2 turbine buildings. To facilitate the crediting of secondary containment bypass leakage deposition in the main condenser to mitigate main control room doses due to the design basis LOCA, the three referenced bypass lines to the main condenser have been seismically verified and quality of the seismically verified equipment is maintained. This approach duplicates the approach used for the main steam isolation valve leakage treatment system described in HNP-2-FSAR subsection 9.5.10.

5.3.3 SAFETY EVALUATION

The secondary containment system provides the principal mechanisms for mitigating the consequences of a fuel-handling accident in the reactor building. The primary and secondary containment systems act together to provide the principal mechanisms for mitigating the consequences of an accident in the drywell. Since the leakage rate of the building is low and the leakage air is filtered and discharged to the elevated release point (utilizing the SGTS and the main stack), the offsite radiation doses resulting from postulated accidents are reduced significantly. The reactor building is a Seismic Class I structure designed in accordance with all applicable codes.

Following the receipt of the isolation signal, the reactor zone and/or refueling zone isolation dampers close, supply and exhaust fans are shut off, and the SGTS is initiated. The SGTS minimizes the release of radioactive material to environs by filtering and exhausting via the main stack.

The main stack provides an elevated release point for airborne activity during the postulated LOCA and fuel-handling accident. Release of activity to the environs from the secondary containment system is analyzed in detail in HNP-2-FSAR chapter 15, Safety Analysis.

5.3.4 INSPECTION AND TESTING

Reactor building (secondary containment system) integrity is demonstrated by activating the SGTS, which establishes and maintains a negative pressure (0.20-in. water) in the secondary containment system as described in subsection 5.3.3. Secondary containment system integrity, as demonstrated by the SGTS, is tested as described in the Technical Specifications.

The SGTS exhaust flowrate is recorded, and the secondary containment system pressure differential with respect to outside ambient conditions is indicated in the MCR.

Tests of the various isolation initiation signals' ability to automatically render the reactor building isolated, trip the supply and exhaust fans, and start the SGTS can be conducted by simulating the isolation signals.

The HEPA filters and charcoal adsorbers are periodically tested in place to verify that no excessive bypass leakage exists.

TABLE 5.3-1 (SHEET 1 OF 5)

TABULATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE(1)

System Name	Pipe Service Description	Isolation Valve Size (in.)	Line Size (2) (in.)	Line Quality(3)	Remarks
Nuclear Boiler System	Main steam to main turbine	24 (each)	24	4	Design basis MSIV leakage has been explicitly considered, separate from the bypass leakage, in the design basis accident radiological consequences analyses.
	Condensate drain	3	3	1	
	Reactor feedwater supply	18 (each)	18	2	Leakage through these lines must flow through three 18-in. check valves in series per line before release to the turbine building.
CS System	Pump condensate supply for test	16	14	1	Note 4.
HPCI System	Pump condensate suction	16	16	1	Note 4.
	Pump flow test line	18	10	1	Leakage must pass through a normally closed MOV that directs flow via the test line to the CST.
	Steam supply to the HPCI turbine	10	1	1	
RCIC System	Pump condensate suction	6	6	1	Note 4.
	Pump flow test line	18	10	1	Leakage must pass through a normally closed MOC that directs flow to the CST via the test line.
	Steam supply to the RCIC turbine	4	1	1	

TABLE 5.3-1 (SHEET 2 OF 5)

System Name	Pipe Service Description	Isolation Valve Size (in.)	Line Size [2] (in.)	Line Quality[3]	Remarks
Radwaste	DW Equipment Drain Sump Discharge	3	3	1	Note 5.
	DW Floor drain Sump Discharge	3	3	1	
	Chemical Drain Sump Discharge	1 1/2	1 1/2	1	Note 5.
RWCU System	RWCU Drainage to main condenser	6	4	1	Note 6.
	Drainage to radwaste	6	4	1	Note 6.
Torus Drainage and Purification System	Torus Drainage to Condenser or Suction to Condensate Pumps	8	3	1	Normally isolated with a minimum of 3 normally closed valves. Also, Note 7.
	Torus Drainage to the Condensate Booster Pumps	8	6	1	Normally isolated with a minimum of 3 normally closed valves. Also, Note 7.
	Torus Drainage to the Waste Surge Tank	8	4	1	Normally isolated with a minimum of 3 normally closed valves. Also, Note 7.
RBCCW System	RBCCW Supply	4	14	1	Closed loop system inside primary containment.
	RBCCW Return	4	14	1	Closed loop system inside primary containment.
DW Pneumatic System	Nitrogen supply from Nitrogen Storage Tanks to DW Pneumatic System	2 (each)	2	1	Note 8.

TABLE 5.3-1 (SHEET 3 OF 5)

System Name	Pipe Service Description	Isolation Valve Size (in.)	Line Size (2) (in.)	Line Quality(3)	Remarks
	DW Pneumatic Suction	1	N/A	N/A	Suction path to the DW pneumatic system compressor has been permanently capped inside the RB. The drain line drains into the RB equipment drain sump and does not bypass the secondary containment.
Neutron Monitoring Sustem	TIP Nitrogen Purge Supply	3/8	2	1	Note 10.
Primary Containment Purge and Inerting System	DW Purge Supply and Nitrogen Makeup	18, 6, 2	2, 6	2	Notes 8, 9.
	DW Exhaust	18, 2, 2, 2	18	1	Processed by the SGTS.
	Torus Purge Supply and Torus Nitrogen Makeup	18, 6, 2	2, 6	2	Notes 8, 9.
	Torus Exhaust	18, 2, 2, 2	18	1	Processed by the SGTS.
	Vacuum Breaker Air Supply	1/2	4	1	The path is normally isolated by 1T48-F342A-L (normally closed). The line will be under instrument air pressure (higher than the torus pressure) if valve 1T48-F342A-L is open.
Plant Service Water System	PSW Supply to DW Coolers	8	10	1	Closed loop system inside primary containment.
	PSW Return from DW Coolers	8	30	1	Closed loop system inside primary containment.

TABLE 5.3-1 (SHEET 4 OF 5)

Demineralized Water System	Demineralized Water Supply to the Hose Stations Inside the DW	1 1/2	4	1	Isolation valve located outside the DW is locked closed during normal plant operation.
Primary Containment Integrated Leak Test System	ILRT Sample Line	3/4	3/4	1	A minimum of 3 isolation valves located outside the DW are closed during normal plant operation.

TABLE 5.3-1 (SHEET 5 OF 5)

NOTES

1. The estimated total bypass leakage from the lines listed in table 5.3-1 does not exceed 2.0% per day of the design containment leakage. This value was chosen to ensure the resultant offsite radiological consequences of the design basis LOCA do not exceed the limits specified in 10 CFR 50.67.

2. Pipe size at the secondary containment wall.

3. Total number of lines that pass through the secondary containment.

4. The lines for HPCI and RCIC system pump suction piping, CST suction piping, and the torus drainage and purification influent piping from the CST are continuously filled with water from the CST to the isolation valve and with suppression pool water to the pump side of the isolation valve. Therefore, no leakage to the environment is postulated to occur.

5. The containment drainage sumps are located in the base of the drywell and are flooded with coolant following the postulated LOCA. This flooding creates a water seal inside the containment up to the closed isolation valves. These valves are leak tested in accordance with 10 CFR 50, Appendix J, and their leakage rates from a part of the total bypass leakage fraction.

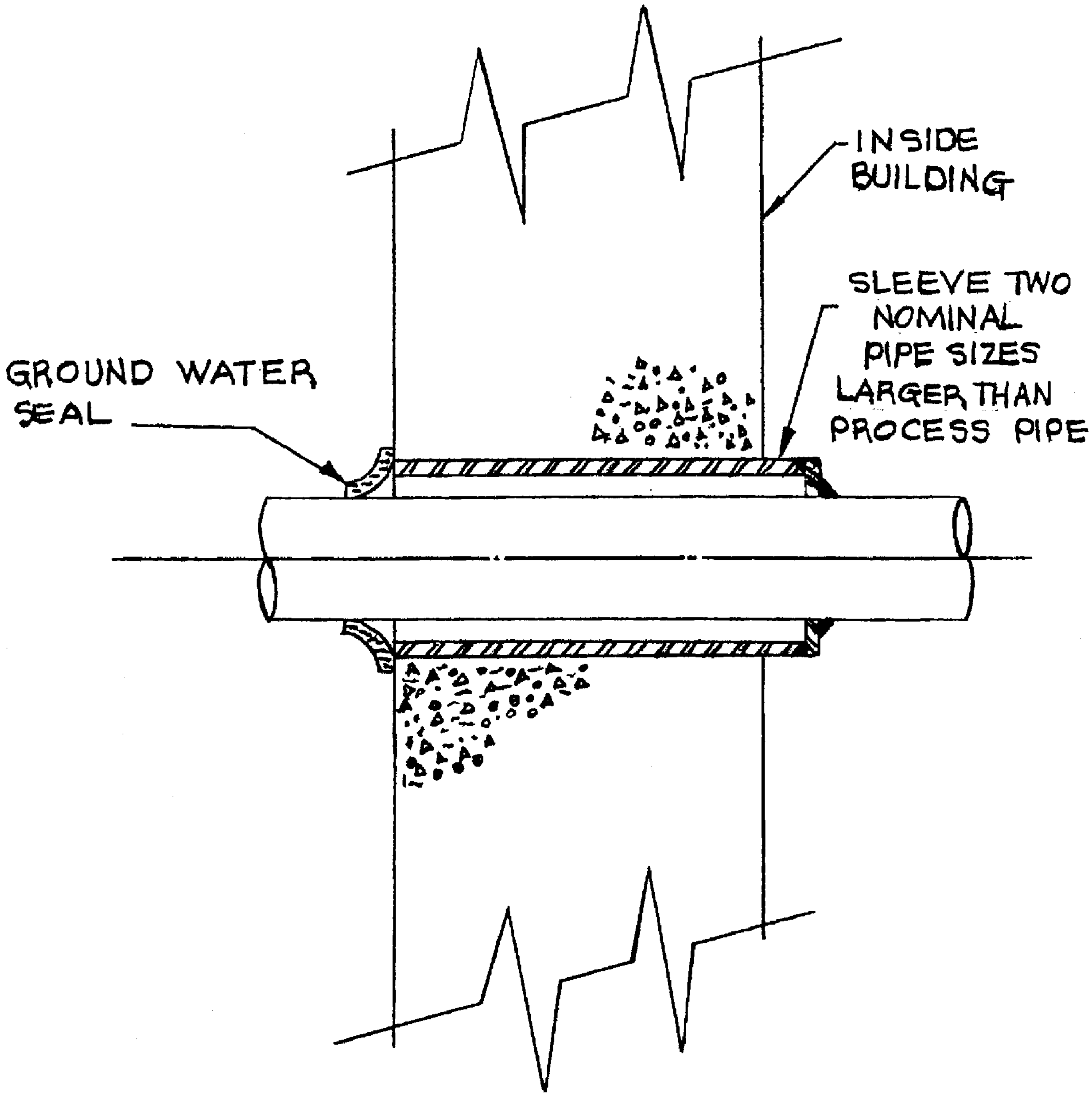
6. The RWC system is isolated from the nuclear process through the closure of two 6-in. isolation valves in series on the influent line, and through the closure of the 18-in. feedwater system check valves at the system effluent, as well as a 3-in. RWCU system effluent check valve. The path to the RCIC is normally isolated. The leakage estimated is the combined leakrate through the 6-in. isolation valves and the 18-in. feedwater check valves. Directing drainage to either the radwaste system or the main condenser does not affect the estimate of bypass leakage since both 4-in. lines connect to the RWCU system loop via the 6-in. and 18-in. isolation valves. See drawing nos. H-16062, H-16145, H-16188, and H-16189.

7. The effluent torus drainage and purification system line, by virtue of its location with respect to the suppression chamber, is always provided with a water seal from the containment.

8. The containment gas purge supply piping is Seismic Category I piping, which is pressurized to a pressure of approximately 120 psig by the Seismic Category I nitrogen supply system, thus precluding the possibility of leakage to the environment from the containment through these lines.

9. The drywell inerting piping is isolated during normal plant operation and is used only during plant startup for DW purge/inerting.

10. The TIP nitrogen supply piping is Seismic Category I piping, which is pressurized to a pressure of approximately 120 psig by the Seismic Category I nitrogen supply system, thus precluding the possibility of leakage to the environment from the containment through these lines.



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TYPICAL REACTOR BUILDING
EXTERIOR WALL PIPE PENETRATION

FIGURE 5.3-1

6.0 EMERGENCY CORE COOLING SYSTEM

6.1 SUMMARY DESCRIPTION

During planned operations when normal electrical power for the plant auxiliaries is available, heat is removed from the reactor core through either the boiling water steam turbine condenser feedwater cycle during power operation, or through the residual heat removal (RHR) system during shutdown. For postulated accident conditions when coolant is lost from a breach in the nuclear process system, the reactor is shut down by either a reactor pressure vessel (RPV) water level 3 or a high drywell pressure scram. Either high drywell pressure or RPV water levels 1 and 2 signals automatically start one or more of the systems to maintain core cooling.

The emergency core cooling system (ECCS) consists of the following subsystems:

- High-pressure coolant injection (HPCI).
- Automatic depressurization (ADS).
- Core spray (CS).
- Low-pressure coolant injection (LPCI), an operating mode of the RHR system.

The ECCS subsystems are designed to limit fuel-cladding temperature over the complete spectrum of possible break sizes in the nuclear system process barrier, including the design basis break. The design basis break is defined as the complete and instantaneous circumferential rupture of the largest pipe connected to the RPV; thus displacing the ends so that blowdown occurs from both ends. The approximate range of operation of the ECCS subsystems to cover the break spectrum is shown in figure 6.1-1.

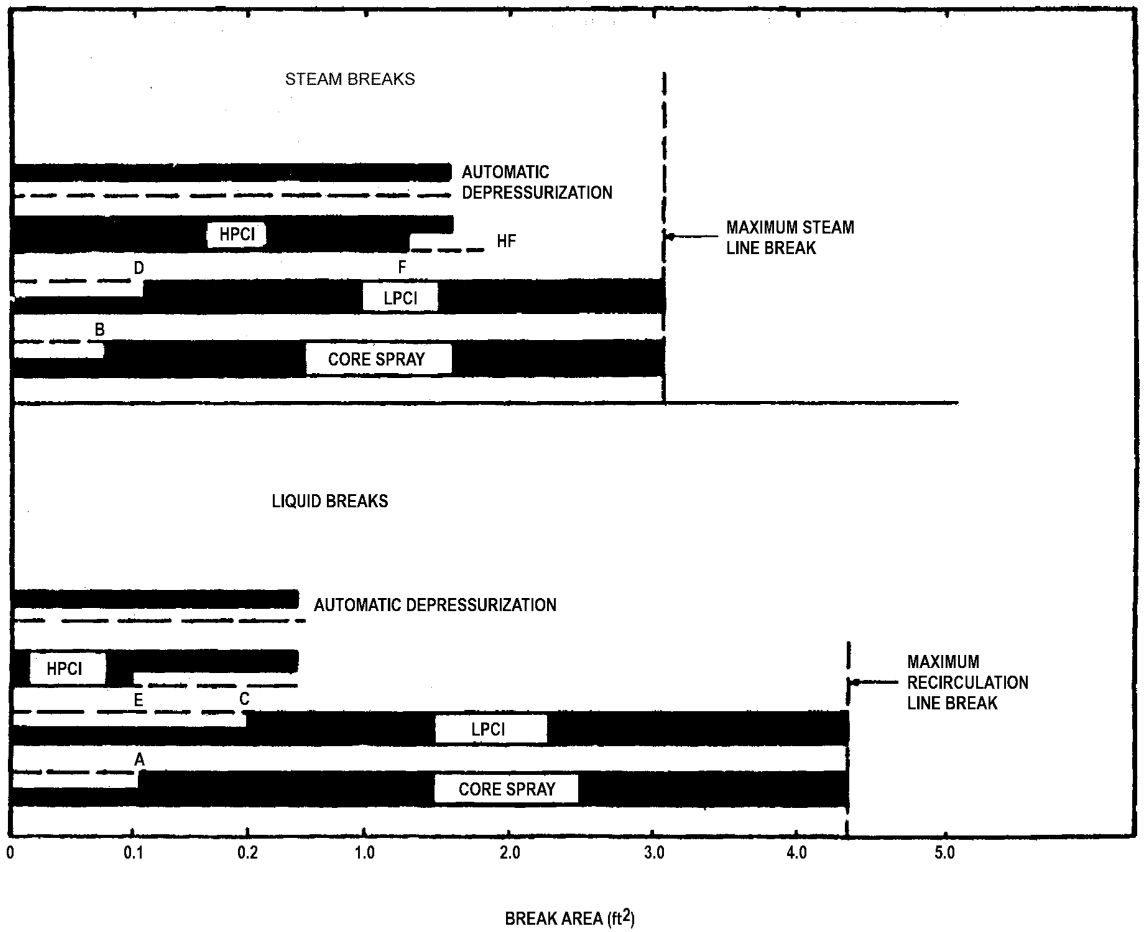
A summary of the principal ECCS parameters (i.e., core cooling capacity, flow, pressure, and backup systems) is included in table 6.1-1. ECCS initiation signals are summarized in figure 6.1-2.

TABLE 6.1-1

ECCS EQUIPMENT DESIGN DATA SUMMARY

Function	No. Installed - Individual Capacity (%)	Design Flow (Each) (flow)	Design Flow (Each) (psid)[a]	Pressure Range (psig)	ac Power Required for Operation	Water Source	Backup Systems
HPCI system	1-100	4250 gal/min	1210-165[b]	1154-150	None	CST and suppression pool	ADS and CS or LPCI
ADS valves	7-20	788,000 lb/h[c]	@1125	1125-50	None		Remote-manual relief valves
CS system	2-100	4000 gal/min	@113	265-0	Normal auxiliary or standby generator	Suppression pool	LPCI
LPCI	4-50	Mode A - 9600 gal/min Mode B - 8700 gal/min	@20	290-0	Normal auxiliary or standby generator	Suppression pool	CS

a. Pounds per square inch differential between the RPV and primary containment.
b. The psid for design flows on HPCI is maximum and minimum; psid measures change with mode of operation.
c. The number of valves assumed in the analysis is 5.



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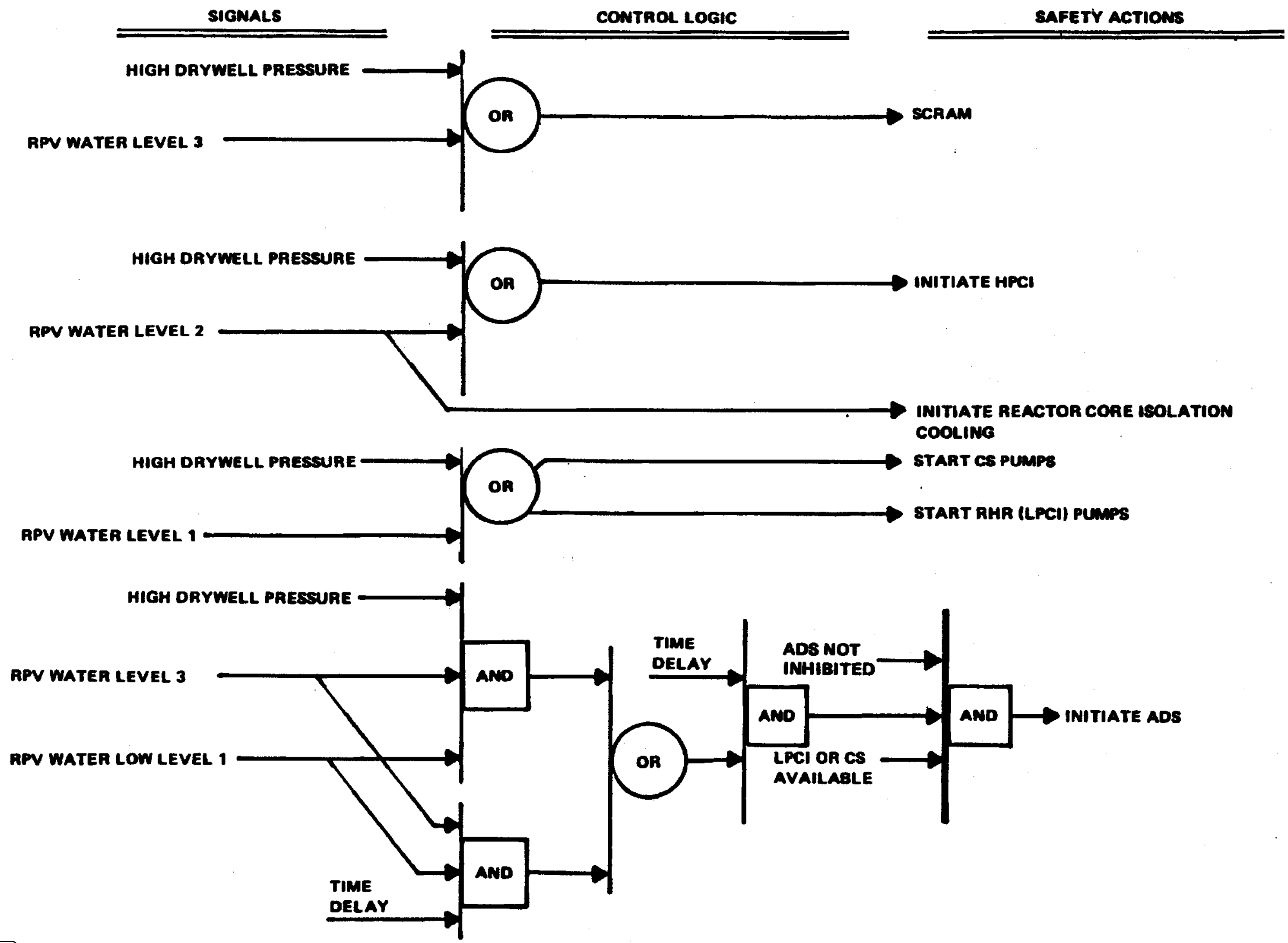
ECCS PERFORMANCE CAPABILITY BAR CHART

FIGURE 6.1-1



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ECCS INITIATION SIGNALS SUMMARY

FIGURE 6.1-2

6.2 SAFETY DESIGN BASES

Cooling systems are designed with diversity, reliability, and redundancy to provide adequate cooling of the reactor core under abnormal and accident conditions.

A. In the event of a loss-of-coolant accident (LOCA), the emergency core cooling system (ECCS) removes residual heat, including stored heat and heat from radioactive decay, to prevent excessive fuel-cladding temperatures.

B. The ECCS provides for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier.

C. The ECCS is initiated automatically by conditions that sense the potential inadequacy of core cooling to limit the degree to which safety is dependent upon the operator.

D. ECCS operation is not dependent upon the availability of offsite power supplies or the power conversion system.

E. Action taken to effect containment integrity does not negate the ability to achieve core cooling.

F. To ensure the ECCS operates effectively, each component required to operate in a LOCA is testable.

G. ECCS components within the reactor vessel are designed to withstand the transient mechanical loadings during a LOCA without restricting the required standby cooling flow.

H. The physical effects of the design basis LOCA (i.e., missiles; fluid jets; and high temperature, pressure, humidity, and radiation) do not prevent the ECCS from effectively cooling the core.

I. The ECCS is capable of withstanding design seismic forces without impairment of their functions.

J. A reliable water source for the ECCS is provided in the primary containment to establish a closed cooling water path during ECCS operation following a LOCA.

6.3 DESCRIPTION

6.3.1 HIGH-PRESSURE COOLANT INJECTION SYSTEM

The high-pressure coolant injection (HPCI) system ensures the reactor is adequately cooled to limit fuel-cladding temperature in the event of a small break in the nuclear system and a loss of coolant that does not result in rapid depressurization of the reactor pressure vessel (RPV).

The HPCI system permits the unit to be shut down while maintaining sufficient RPV water inventory until the reactor is depressurized. The HPCI system continues to operate until RPV is below the pressure at which either operation of the low-pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system or the core spray (CS) system maintain core cooling.

If a loss-of-coolant accident (LOCA) occurs, the reactor scrams upon receipt of an RPV water level 3 signal or a high drywell pressure signal. The HPCI system initiates upon receipt of an RPV water level 2 signal or if high pressure exists in the drywell. The HPCI system automatically stops upon receipt of an RPV water level 8 signal. The approved LOCA ECCS analysis does not take credit for HPCI operation to ensure 10 CFR 50.46 requirements are met.

The HPCI system consists of a steam turbine that drives a constant flow pump, system piping, valves, controls, and instrumentation. The system is shown schematically on drawing no. S-16122.

The principal HPCI system equipment is installed in the reactor building. The turbine pump assembly is located in a shielded area to assure personnel access to adjacent areas is not restricted during operation of the HPCI system. Suction piping comes from the condensate storage tank (CST) and the suppression pool. Injection water is piped to the reactor feedwater pipe at a T-connection. Steam supply for the turbine is piped from a main steam header in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the main control room (MCR). The controls and instrumentation of the HPCI system are described and evaluated in detail in section 7.4, Emergency Core Cooling System Control and Instrumentation.

The HPCI system is designed to pump water into the RPV for a wide range of RPV pressures. Two water sources are available.

A. Initially, the HPCI system uses demineralized water from the CST. Approximately 100,000 gal of the 500,000-gal CST are held in reserve for the HPCI and reactor core isolation cooling (RCIC) systems. System demands on the CST, other than HPCI and RCIC, draw from a tank internal standpipe. The inlet to this standpipe is set at a level so that ~ 100,000 gal are below the intake and unavailable to the other systems. Both the HPCI and RCIC systems connect separately to the CST near the bottom. In addition, the CST has a backup capacity from the 100,000-gal demineralized water storage tank.

B. Should the CST be drawn down to a low level, automatic transfer to the suppression pool occurs.

Water from either source is pumped into the RPV via a feedwater line. Flow is distributed within the RPV through the feedwater spargers, thus causing mixing with the hot water or steam in the RPV.

To ensure positive suction head to the pump, the pump is located below the level of the CST and below the water level in the suppression pool. The pump meets net positive suction head requirements by providing adequate suction head and adequate suction line size.

The location of the HPCI system turbine pump assembly and piping outside the primary containment provides protection from the physical effects of design basis accidents, such as pipe whip and high temperatures.

Steam from the reactor drives the HPCI system turbine. Decay heat and stored heat generate steam that is extracted from a main steam header upstream of the main steam isolation valves. The two HPCI system isolation valves in the steam line to the system turbine are normally open to keep piping the turbine at elevated temperatures and to permit rapid startup of the HPCI system. Signals from the control system open or close the turbine stop valve.

To prevent the HPCI system steam supply line from filling with water, a condensate drain pot located upstream of the turbine stop valve normally routes condensate to the main condenser. However, upon receipt of a HPCI system initiation signal or loss of control air pressure, isolation valves on the condensate line shut automatically.

The following two devices control turbine power:

1. A speed governor limits turbine speed to its maximum operating level.

2. A control governor with an automatic speed setpoint control is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCI system operation.

   When the governor is in the test mode, it can be operated manually; however, the demand signal from the flow controller automatically repositions the governor if system initiation is required.

As RPV steam pressure decreases, the HPCI system turbine throttle valve opens wider to permit passage of the steam flow required to provide necessary pump flow. The capacity of the system provides sufficient core cooling to prevent clad melting while RPV pressure exceeds that at which CS and LPCI become effective.

Exhaust steam from the HPCI system turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects condensate that is discharged to the gland-seal condenser.

The HPCI system turbine gland seals are vented to the system gland-seal condenser, and part of the water from the system pump is routed through the condenser for cooling purposes. Noncondensible gases from the gland-seal condenser are exhausted to the reactor building exhaust system. Under conditions of high radioactivity levels in the reactor building, the exhaust system is isolated and vented through the standby gas treatment system.

HPCI system piping is designed in accordance with the requirements stated in appendix A.

HPCI system equipment piping and support structures are designed as Seismic Class 1 equipment.

Erosion, corrosion, and material fatigue are accounted for in the design of the HPCI system. Aging management programs (HNP-2-FSAR subsections in 18.2.1, 18.2.6, 18.2.9, 18.2.12, 18.3.2, and 18.4.5) monitor the condition of the HPCI system components so that actions are taken to provide reasonable assurance that these components are capable of performing their intended functions for 40 years and beyond.

Startup of the HPCI system is completely independent of ac power. For startup to occur, only dc power from the plant batteries and steam extracted from the nuclear system are required.

Various operations of HPCI system components are summarized as follows:

A. HPCI system controls automatically start the system and bring it to design flowrate within 75 s from receipt of an RPV water level 2 signal or a high drywell pressure signal.

   The maximum allowable time delay from the onset of actuating conditions for the initiating signal to injection valve wide open and rated flow availability is 75 s.

B. The HPCI system turbine is shut down automatically by any of the following signals:

   1. Turbine overspeed prevents damage to the turbine and the turbine casing.

   2. RPV water level 8 indicates core cooling requirements are satisfied.

   3. HPCI system pump low-suction pressure prevents damage to the pump due to loss of flow.

   4. HPCI system turbine exhaust high pressure indicates a turbine or turbine control malfunction.

C. If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

D. Because the steam supply line to the HPCI system turbine is part of the nuclear system process barrier, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in section 7.3, Primary Containment and Reactor Vessel Isolation Control System. However, the automatic depressurization system (ADS) and the low-pressure ECCS subsystems act as backup; automatic shutoff to the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

E. In addition to the automatic operational features of the system, remote manual startup, operation, and shutdown capabilities are provided (if initiation or shutdown signals do not exist). All automatically operated valves are equipped with a remote-manual functional test feature.

F. HPCI system initiation automatically actuates the following valves:

- Pump discharge test bypass valves.
- Pump suction shutoff valves.
- Pump discharge shutoff valves.
- Steam supply shutoff valves.
- Turbine stop valve.
- Turbine control valve.
- Steam supply line drain isolation valves.
- Cooling water drain isolation valves.

G. The hydraulic oil pump must be started and the hydraulic control system must be functioning properly before the turbine valves can be opened. The gland-seal condenser components must be operating to prevent outleakage from the turbine shaft seals. Startup of the equipment is automatic; however, its failure does not prevent the HPCI system from fulfilling its core cooling objective.

When rated flow is established, the flow controller signal adjusts the setting of the control governor to maintain rated flow as nuclear system pressure decreases.

H. A minimum-flow bypass is provided for pump protection. The bypass valve automatically opens on a low-flow signal and automatically closes on a high-flow signal. When the bypass is open, flow is directed to the suppression pool. A system test line provides recirculation to the CST during system tests. Shutoff valves are provided with proper interlocks that automatically close the test line upon receipt of a HPCI system initiation signal. The HPCI system is declared inoperable while in the test mode.

6.3.2 AUTOMATIC DEPRESSURIZATION SYSTEM

The ADS provides automatic nuclear system depressurization for small breaks with maloperation of the HPCI system so LPCI and the CS system can operate. The relief capacity of the ADS is based upon the time required after its initiation to depressurize the nuclear system so the CS system and LPCI can cool the core.

The ADS uses seven of the nuclear system pressure relief valves to relieve high-pressure steam to the suppression pool. The design, description, and evaluation of the pressure relief valves are discussed in detail in section 4.4.

To operate, the ADS control logic must have sensed high drywell pressure and RPV water levels 1 and 3 or a sustained RPV water level 1 signal after an approximate 13-min time delay with an RPV water level 3 signal. The logic starts the 130-s timer and, if a signal indicating at least one LPCI or one CS pump is running (discharge pressure permissive) is received, the ADS will actuate. The 130-s time delay allows time for either LPCI or the CS system to start.

However, an anticipated transient without scram (ATWS) event can generate the above ADS initiation signals, although ADS is not required or desired. The operator can manually prevent ADS initiation during an ATWS event through two keylocked ADS inhibit switches in the MCR. This action enhances the standby liquid control (SLC) system's effectiveness in shutting down the reactor during an ATWS event.

6.3.3 CORE SPRAY SYSTEM

The CS system protects the core by removing decay heat following the postulated design basis LOCA.

The protection provided by the CS system also extends to a small break (figure 6. 1-1) in which the control rod drive (CRD) water pumps, the RCIC system, and the HPCI system are unable to maintain RPV water level, and the ADS has operated to lower the RPV pressure so that LPCI and the CS system can provide core cooling.

The CS system consists of two independent loops. Each loop includes one 100% capacity centrifugal water pump driven by an electric motor, a spray sparger in the RPV above the core, piping and valves that convey water from the suppression pool to the sparger, and associated controls and instrumentation. Drawing no. S-15117 is a schematic process diagram of the CS system.

Actuation of the CS system results from an RPV water level 1 signal or high drywell pressure. When RPV pressure is low enough, the CS system automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flowrate to cool the core and limit fuel-cladding temperature. (The same signals start LPCI, which operates independently to flood the RPV to achieve the same objective.)

The CS pumps receive power from the 4160-V emergency auxiliary buses. Each CS pump motor and associated automatic motor-operated valves (MOVs) receive ac power from a different bus. Similarly, the control power for each loop of the CS system comes from different dc buses (chapter 8).

The CS pumps and all automatic valves can be operated individually by manual switches in the MCR. Pressure indicators, flow meters, and indicator lights provide operating information in the MCR.

The following paragraphs describe the major equipment for one of two identical loops.

When the system is actuated, water is taken from the suppression pool. Flow then passes through an air-operated butterfly valve (drawing no. H-19945), and through a motor-operated gate valve which is normally open but which can be closed by a remote manual switch from the MCR. Closure isolates the system from the suppression pool in the case of CS system leakage. The air-operated valve (AOV) is located in the CS pump suction line as close to the suppression pool as practical.

A local pressure gauge for each pump indicates the presence of a suction head for the pump. The CS pumps are located in the reactor building below the water level in the suppression pool. Their position assures positive pump suction. Separation of the pumps, piping, controls, and instrumentation of each loop is such that any single physical event cannot render both CS loops inoperable. The switchgear for each loop is located in a separate room for the same reason.

A low-flow bypass line runs from the pump discharge to below the surface of the suppression pool. The bypass valve opens automatically on a low-flow signal and closes automatically on a high-flow signal. The bypass flow is required to prevent the pump from overheating when pumping occurs against a closed discharge valve. An orifice limits the bypass flow.

The CS system discharge line to the RPV has one 10-in. check valve and one 10-in. MOV. Positioning of the MOV is indicated in the MCR. The MOV is normally closed and cannot be opened (pressure switch interlock) to overpressurize the low-pressure (460-psig design) piping system.

Because the discharge line in the CS system has two isolation valves in series with independent control, a single operator error or equipment malfunction can prevent one, but not both, of the valves from providing the overpressure protection. Since the failure of one valve to provide overpressure protection does not preclude protection by the other valve, the pressure interlock on one valve need not meet the single-failure criterion. If the isolation valves fail to provide overpressure protection and overpressurization occurs, splitting of pipe sections near welds might be expected.

A relief valve protects the CS system upstream of the outboard shutoff valve from RPV pressure. The relief valve discharges to the radwaste system.

A full-flow test line admits circulating water to the suppression pool and allows the system to be tested during normal plant operations. A remote manual switch in the MCR operates an MOV in the normally closed line. Partial opening of the valve and an orifice in the test line provide CS flow rated at a pressure drop equivalent to that of discharge into the RPV. A loop flow indicator is located in the MCR.

Two MOVs in each loop isolate the CS system from the nuclear system when the CS pump is not running. When signaled to open, the MOVs admit CS water to the RPV. To facilitate operation and maintenance, both valves are installed outside the drywell; however, they are placed as close to the drywell as practical to limit the length of line exposed to RPV pressure. The valve nearer the containment is normally closed to back up the inside check valve in controlling reactor coolant leakage. The outboard valve is normally open to limit the equipment needed to operate in an accident condition. When the outboard valve is closed, the inboard valve can be operated for test with the RPV pressurized. A vent line located between the two shutoff valves can be used to measure leakage through the inside check valve or the inboard shutoff valve. To assure containment, the vent line is normally closed with two valves (at least one of which is locked closed) and a pipe cap.

A check valve in each CS pipeline inside the primary containment prevents loss of reactor coolant outside the containment in case the CS line breaks. A normally locked-open manual valve located downstream of the inside check valve shuts off the CS system from the reactor during shutdown to permit maintenance of the upstream valves. The two pipes in the CS system enter the RPV through nozzles located 180° apart. Each internal pipe divides into a semicircular header (with a downcomer at each end) that turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to form two circles, one above the other and both essentially complete. Short elbow nozzles are spaced around the spargers to spray water radially onto the top of the fuel assemblies.

The CS piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the CS pump discharge. The outboard valve and piping downstream are designed for RPV pressure and temperature. The pressure piping is designed in accordance with appendix A requirements.

The CS equipment, piping, and support structures are designed in accordance with Seismic Class 1 criteria to resist motion effected by the design basis earthquake at the installed location within the supporting building. For seismic analysis, the CS system is assumed to be filled with water.

An RPV water level 1 signal or high drywell pressure signals the automatic controls to energize the CS pumps. When RPV pressure decreases, the CS shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Section 7.4 gives further details and evaluation.

6.3.4 LOW-PRESSURE COOLANT INJECTION

In case of an RPV water level 1 signal from the RPV or high drywell pressure, the LPCI mode of RHR pumps water into the RPV in time to flood the core and limit fuel-cladding temperature. (The same signals start the CS system, which operates independently to achieve the same objective.)

LPCI operation protects the core in case a large break in the nuclear system occurs when the CRD water pumps, the RCIC system, and the HPCI system are unable to maintain RPV water level.

LPCI protection also extends to a small break (figure 6. 1-1) in which the CRD water pumps, the RCIC system, and the HPCI system all are unable to maintain RPV water level, and the ADS has operated to lower the RPV pressure so that LPCI and the CS system can provide core cooling.

Drawing nos. S-15304 and S-15305 comprise a schematic process diagram of LPCI. Each loop of LPCI operation consists of two ac motor-driven centrifugal pumps that take water from the suppression pool and pump it into one of the two recirculation loops. The water enters the RPV through jet pumps and restores water level.

The LPCI pumps receive power from the 4160-V emergency auxiliary buses. The LPCI pump motors assigned to each loop receive ac power from different buses. A combination of HNP-2 600-V ac load centers backed by HNP-2 dedicated diesel generators and an HNP-1 600-V ac motor control center backed by swing diesel generator 1B supply power to the MOVs associated with LPCI operation (HNP-2-FSAR figure 8.3-8).

LPCI pumps and piping equipment are described in detail in section 4.8. Also described are other functions served by the same pumps if they are not needed for the LPCI function. Portions of the RHR system required for accident protection are designed in accordance with Seismic Class 1 criteria.

6.4 SAFETY EVALUATION

6.4.1 SUMMARY

To satisfy the safety design bases, four emergency core cooling system (ECCS) subsystems are provided:

- High-pressure coolant injection (HPCI).
- Automatic depressurization.
- Core spray (CS).
- Low-pressure coolant injection (LPCI), an operating mode of the residual heat removal (RHR) system.

These subsystems are in addition to the other systems that supply core coolant: feedwater, control rod drive (CRD), and reactor core isolation cooling (RCIC).

For reliability, each ECCS subsystem uses equipment with the least required components to actuate as feasible. Each component required to operate in a loss-of-coolant accident (LOCA) is testable. To provide diversity, two cooling methods, spraying and flooding, are provided. Flood protection for the RCIC, RHR, HPCI, and CS systems is provided as follows.

The diagonal rooms housing the equipment for RCIC, RHR, HPCI, and CS are designed for the hydrostatic load resulting from flooding due to torus leakage. The rooms are separated from the torus room by 2-ft-thick concrete walls for the entire height of the torus room and each construction joint is provided with waterstop to prevent water leakage.

The maximum height of flooding of the torus room was calculated assuming design basis accident (DBA) torus water volume. All pipe penetrations below this level in the diagonal walls are sealed.

The leak detection system (LDS) sumps for the torus compartment and the HPCI, RCIC, RHR, CS, and CRD equipment rooms are interconnected in either the north or south region. All sumps are equipped with level alarms and a system of remotely operated valves to prevent flooding of compartments other than the compartment in which a leak occurs. Figure 4.10-5 is a schematic diagram of the LDS system.

Entry into the diagonal rooms is from the floor above the torus room at el 130 ft msl; hence, flood protection barriers are not required to be broken for entry.

Evaluation of the reliability and redundancy of the controls and instrumentation for the ECCS shows that no failure of a single initiating sensor either prevents or falsely starts the initiation of these cooling systems. No single control failure prevents the combined cooling subsystems from providing the core with adequate cooling. The controls and instrumentation can be calibrated and tested to ensure proper response to conditions representative of accident situations.

As stated in the safety design bases, the ECCS removes residual and decay heat from the reactor core to prevent fuel-cladding melting.

The performance evaluation of the HNP-1 and HNP-2 ECCS for mitigation of a design basis LOCA is contained in HNP-2-FSAR subsection 6.3.3. Peak-cladding temperatures (PCTs) for core reloads are calculated using the LOCA methodology described in HNP-2-FSAR subsection 6.3.3. Evaluation of the cooling performance of the combined ECCS susbsystems is calculated using an analytical model and covers the spectrum of conditions in detail to ensure core cooling is adequate across the entire spectrum of break sizes.

6.4.2 PERFORMANCE ANALYSIS

The manner in which the ECCS subsystems operate to protect the core is a function of the rate at which coolant is lost from the break in the nuclear process system boundary. If the break in the nuclear process system boundary results in the loss of coolant exceeding the capacity of the HPCI system, nuclear system pressure drops at a rate fast enough for the CS system and LPCI to pump additional coolant into the reactor pressure vessel (RPV) in time to cool the core.

Automatic depressurization automatically reduces nuclear system pressure if a break occurs, and the HPCI system and the other water addition systems cannot maintain RPV water level. Rapid depressurization of the nuclear system is desirable to permit flow from the CS system and LPCI to enter the RPV to limit the temperature rise in the core.

If, for a given size break, the HPCI system has the capacity to make up for all the coolant loss from the nuclear system, flow from the low-pressure portion of the ECCS is not required for core protection until nuclear system pressure decreases below ~ 150 psig. Either LPCI or the CS system is capable of pumping water into the RPV at a nuclear system pressure < 150 psig.

The redundant features of the ECCS are shown in bar chart form on figure 6.1-1. The capability for cooling exists over the entire spectrum of break sizes even with concurrent loss of normal auxiliary power and in the event one of the high-pressure systems (i.e., HPCI system or ADS) and one of the low-pressure systems (i.e., CS system or LPCI) are unavailable.

A high drywell pressure or an RPV low-low-low water level signal starts LPCI, the CS system, and the standby ac power supply (table 8.4-4).

6.4.2.1 (Deleted)

6.4.2.2 <u>HPCI System</u>

The HPCI system is designed to provide adequate reactor core cooling for small breaks and depressurize the reactor primary system so that LPCI and the CS system can be initiated.

When the HPCI system begins operation, the RPV depressurizes more rapidly than would occur if HPCI was not initiated due to the condensation of steam by the cold fluid the HPCI system pumps into the RPV. As RPV pressure continues to decrease, the HPCI system momentarily reaches equilibrium with the flow through the break. Continued depressurization causes the break flow to decrease below the HPCI system flow, and the liquid inventory begins to rise. This type of response is typical of the small breaks. The core never uncovers and is continuously cooled throughout the transient so that no core damage occurs for breaks that lie within the range of the HPCI system.

An analysis was performed to determine whether any carryover in the steam supply to the HPCI system turbine can have a detrimental effect on turbine operation. If a break occurs in a liquid line when the HPCI system is energized, RPV water level is low enough to prevent carryover in the steam leaving the RPV. If a small break in the reactor region occurs simultaneously with loss of normal ac power, reactor scram, recirculation pump coastdown, and loss of feedwater, analysis shows that the initial decrease of pressure in the reactor results in no significant level swell and no carryover of water into the steam supply to the HPCI system turbine. HPCI system cold water quenches any steam formation in the downcomer region. After the HPCI system has been operating, and as the level rises in the RPV, natural circulation within the RPV is established, and any steam to the HPCI system turbine passes through the steam separators and dryers, eliminating any moisture carryover. Since a mechanism to cause bypassing of the steam separators by the swelling steam water mixture is not available, gross moisture carryover to the HPCI turbine should not occur over the range of steam line breaks of interest in the HPCI system.

The HPCI turbine is designed for high reliability under its design requirements of quick starting. HPCI turbine efficiency is not of paramount importance. Moreover, the turbine has adequate capacity to accept the small losses in efficiency due to any credible moisture carryover.

Analyses for the spectrum of small breaks determine the capability of the HPCI system for the liquid pipe break and a steam pipe break. The half-width extension of the bar (figure 6.1-1) indicates the additional range of break sizes for which the HPCI system, in conjunction with LPCI or the CS system, prevents excessive fuel-cladding temperatures. No credit is taken for HPCI operation in the approved LOCA analyses to ensure 10 CFR 50.46 requirements are met.

6.4.2.3 ADS

When the ADS is actuated, the flow of steam through the valves provides a maximum energy removal rate, while minimizing the corresponding fluid mass loss from the RPV. Thus, the internal energy of the saturated fluid in the RPV is rapidly decreased causing pressure reduction. No credit is taken for the steam cooling of the core caused by ADS actuation to provide further conservatism to the ECCS performance analysis. Performance analysis of the ADS is considered only with respect to its depressurizing effect in conjunction with either LPCI or the CS system. The effective range of the ADS is presented in figure 6.1-1. The ADS provides the backup for the HPCI system.

Actuation of the automatic depressurization function does not require an offsite power source. The relief valves require dc power from the plant batteries for control and air power from the accumulators for operation.

An anticipated transient without scram (ATWS) event can generate ADS initiation signals even though ADS is not required or desired. The operator can manually prevent ADS initiation during an ATWS event through two keylocked ADS inhibit switches in the main control room (MCR). This action enhances the standby liquid control (SLC) system's effectiveness in shutting down the reactor during an ATWS event.

The accumulators and the nuclear system relief valves are located within the primary containment.

6.4.2.4 CS System

The CS system is designed to maintain continuity of reactor core cooling for a large spectrum of LOCAs. Each loop provides adequate cooling for intermediate and large line break sites up to and including the design basis double-ended recirculation line break, without assistance from any other ECCS subsystems.

The approximate effective range of the CS system for various break sizes is shown in figure 6.1-1. When the injection valve begins to open because RPV pressure is low enough, water is injected from the sparger, although at less than rated flow until differential pressure (ΔP) fully opens the injection valve. The half-width portion of the bar shows the overlap with the other ECCS subsystems.

There is a break size below which the CS system alone cannot protect the core (figure 6.1-1), because RPV pressure does not drop rapidly enough to allow sufficient CS injection before the cladding hot spot reaches excessively high temperature. Below this break size, either the HPCI system or the ADS extends the range of the CS system to breaks of insignificant magnitude.

Experimental tests show that the quantity of flow currently being provided for CS is greatly in excess of the minimum actually required for satisfactory core cooling.(1) The tests show that more than the minimum flow required is readily attained for every fuel assembly. Other tests include evaluation of the effects of updraft caused by steam flow through the core or evaporation of the water that enters the fuel assembly. The effects of updraft are minor. A series of tests were performed to obtain design data relating to distribution of CS coolant over the top surface of the reactor core. Reference 1 contains a description of the test facility and plots of the significant test results.

The CS tests also provide experimental effective heat transfer coefficients, thus enabling correlation of the core heatup model with the actual test data. Data from tests on an exact prototype at power result in volume percentile temperature distributions. The close correlation between the peak temperature and general trend demonstrates the adequacy of the analytical models employed.

To ensure continuity of core cooling, signals to isolate the primary or secondary containment do not operate any CS system valves.

Inboard check valve 1E21-F006A&B is the only CS component in the primary containment required to actuate during a LOCA. The valve is exposed to the high temperature and humidity existing in the containment as a result of the accident. However, the selected valve actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor the accident environment in the containment affects the operability of the CS components.

Taking the CS water from the suppression pool establishes a closed loop for recirculation of the spray water escaping from the break.

6.4.2.5 LPCI

The LPCI mode of the RHR system automatically refloods the reactor core in time to limit cladding temperatures following a nuclear system LOCA when the RPV pressure is below the shutoff head of the pumps. LPCI provides cooling by flooding, while the CS system provides cooling by spraying.

The LPCI pumping system is designed with both adequate head and adequate coolant-flow capacity to meet flooding requirements for the entire break spectrum, when operating in conjunction with either the HPCI system or the ADS.

The maximum-flow capacity is determined by the design break (instantaneous recirculation line break). The pumps are capable of refilling the lower plenum well before excessive cladding temperatures occur, even assuming no water remains following the blowdown. The minimum allowable time in which this must be done occurs for the design break, because the least core cooling occurs for this break. Hence, the design break must achieve reflooding more quickly than small breaks. However, the RPV depressurizes very quickly for the design break, and therefore, a greater quantity of water can be pumped due to the pump head-flow characteristic.

The maximum RPV pressure against which the LPCI pumps must deliver some flow is determined by the required overlap with HPCI which is a low-pressure cutoff for the HPCI turbine at ~ 100 psig.

LPCI cooling capability is analyzed by the computer methods summarized previously, based upon the mass and energy flows to and from the reactor. The break in the nuclear process system barrier is assumed to occur instantaneously and simultaneously with loss of normal auxiliary ac power.

A general description of the LPCI response to a LOCA is as follows:

1. For the first few seconds, the feedwater and recirculation pumps coast down, providing makeup to LPCI and nearly normal recirculation flow; however, no credit is taken in the analysis for these phenomena.

2. The liquid inventory decreases rapidly, limited by the critical flowrate through the break.

3. The accident initiation signals direct both LPCI injection valves to open upon detection of accident conditions. In addition, both recirculation loop discharge valves (downstream of the recirculation pumps) are signaled to close when RPV pressure decreases to an appropriate setting following detection of accident conditions. After the LPCI startup sequence is complete, flow commences in both loops. These actions provide a direct flow path for the injection of the LPCI flow into the bottom plenum of the RPV.

4. As LPCI flow accumulates, the level rises inside the shroud. When the level reaches the top of the jet pumps, spillover occurs for a time, raising the level outside the shroud.

5. As the subcooled LPCI flow begins spilling into the region outside the shroud, the depressurization effect of the break is reduced, since the subcooled water is now flowing out of the break.

6. As the pressure begins to rise, LPCI flow is reduced until a quasi- equilibrium pressure is reached. At this point, the break is partially covered by subcooled water that has spilled over the top of the jet pumps and the equivalent area of the break available for steam blowdown is reduced.

7. LPCI spillage maintains, at the required equilibrium value, the size of the break available for steam blowdown. However, this condition is not actually attained because of how the HPCI system and ADS affect the transient. Although HPCI system flow is lost when pressure is reduced sufficiently, the auto depressurization valves will open as level continues to drop.

The effective range of LPCI alone for the spectrum of steam or liquid line breaks is shown in figure 6.1-1. The half-width portion of the bar shows the overlap with the other ECCS subsystems.

To ensure continuity of core cooling, signals to isolate the primary or secondary containment do not operate any LPCI valves.

The recirculation pump discharge valves and two check valves (one in each loop) are the only LPCI-related components in the primary containment that are required to actuate during a LOCA, and that require consideration for the high temperature and humidity existing in the containment as a result of the accident. The discharge valve is qualified for the worst postulated accident conditions. The check valve actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor the accident environment within the containment affects the operability of LPCI equipment for the accident.

Using the suppression pool as the water source for LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

6.4.3 ECCS INTEGRATED OPERATION

The performance evaluation of the HNP-1 and HNP-2 ECCS for mitigation of a design basis LOCA is contained in HNP-2 subsection 6.3.3. The analysis is performed using a nominal power level of 2804 MWt. For discussions of the HNP-1 and HNP-2 ECCS suction line rupture analysis, pump net positive suction head (NPSH) analysis, and pump suction strainer analysis, reference HNP-2 FSAR paragraphs 6.3.3.8, 6.3.3.9, and 6.3.3.10, respectively.

6.4.4 ECCS REDUNDANCY

The design criterion of preventing PCTs > 2200°F is satisfied across the entire spectrum of possible liquid or steam line break sizes by at least two separate and independent systems and by two different modes of core cooling, even in the event of the loss of normal auxiliary power.

In addition, redundancy in the ECCS exists. Effective core cooling is achieved, even when the most limiting single equipment failure and the most limiting break location are considered. The postulated failures include those that will disable one of the two 100% capacity CS loops and two of the four LPCI pumps. In case of a design basis LOCA, at least two low-pressure ECCS pumps will be available for core cooling, considering both the limiting equipment failure and any possible loss of ECCS flow directly out of the pipe break. Analyses show that the ECCS pumps that will be available in all cases are sufficient to maintain the PCT < 2200°F.

The redundant capability of the ECCS is sufficient to ensure the acceptance criteria for all size line breaks up to and including the design basis break are satisfied.

6.4.5 ACCIDENT MONITORING

For a discussion of ECCS instrumentation requirements, reference HNP-2-FSAR paragraph 6.3.2.16.

6.4.6 (Deleted)

6.4.7 (Deleted)

REFERENCES

1. "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," General Electric Company, Atomic Power Equipment Division, APED-5458, March 1968.

6.5 INSPECTION AND TESTING

For a description of ECCS active component testing, reference HNP-2-FSAR paragraph 6.3.2.17.

7.0 CONTROL AND INSTRUMENTATION

7.1 SUMMARY DESCRIPTION

This chapter presents the details of the major control and instrumentation systems for HNP-1. Some of these systems are safety systems, while others are power generation systems. The list of safety-related instrumentation, control, and electrical systems diagrams forwarded to the Nuclear Regulatory Commission (NRC) is included in table 7.1-1.

7.1.1 SAFETY SYSTEMS

The safety systems described in the control and instrumentation chapter are the following:

A. Nuclear safety systems and engineered safeguards required for accidents and anticipated operational occurrences (AOOs).

- Reactor protection system (RPS).
- Primary containment and reactor vessel isolation control system.
- Emergency core cooling system (ECCS).
- Neutron monitoring system (NMS) (specific portions).
- Process radiation monitoring systems (PRMSs).
- Low-low set (LLS) relief logic.
- Analog transmitter trip system (ATTS).

B. Process safety systems (required for planned operation).

- NMS (specific portions).
- Refueling interlocks.
- Reactor vessel instrumentation.

The standby liquid control system, which is manually initiated, is described in section 3.8. The standby gas treatment system (SGTS) and its initiation are discussed in paragraph 5.3.3.3.

The following instrument systems provide information only for protective action by the operator:

- H_2 and O_2 analyzer for primary containment.

- Fission products monitor for primary containment.
- Primary containment pressure monitor.
- Primary containment temperature monitor.
- Suppression pool water level recorder.

The objective of the above systems is to provide the operator with information when an abnormal condition exists so that appropriate, corrective action can be taken.

The design basis for these systems is to record continuously the variable phenomena and to annunciate each when predetermined setpoints are reached.

Each system consists of redundant detection or analyzer devices, recorders, and annunciators. All are designed to comply with the intent of Institute of Electrical and Electronics Engineers (IEEE) 279, except for design requirements 4.1, 4.16, and 4.17. In addition, recorders and indicators associated with these systems take exception to IEEE 279 design requirements 4.3 and 4.4.

The following general test methods are followed to meet IEEE 279, periodic testing of engineered safety feature (ESF) instrumentation and control equipment:

A. Provisions are made for functional testing without requiring shutdown or unscheduled power change as a condition of the test. Tests do not impair functional capability of ESF instrumentation and control equipment; i.e., redundant trip systems are not tested simultaneously.

B. Generally, where practicable, testing is accomplished without disturbing the existing wiring or components; i.e., lifting of wires or removal of components is not a preferred test method.

C. Where practicable, the use of clip-leads is avoided.

D. Test jacks permanently wired to existing circuitry are considered acceptable provided the connection points are so chosen that no portion of the installed protective wiring is untestable and that external equipment connected to the test jacks is a conspicuous departure from normal conditions.

E. Permanently wired test lights are acceptable provided that the installation is not capable of producing an unsafe failure through any malfunction of the lamp.

Sensors that actuate ESFs comply with the testability requirements of IEEE 279.

Most of the sensors or ATTS sensors/trip units provide a digital contact output to the particular protection system involved. These sensors are tested by valving the instrument out-of-service and introducing an artifical pressure or similar variable to exercise the instrument to the established trip setpoint. After this calibration test, the instrument is valved back into service. The ATTS sensors/trip units are tested per paragraph 7.18.2.9.

A few sensors, such as ATTS, main steam line high-radiation and neutron monitoring average power range monitor and intermediate range monitor channels, involve a continuous analog measurement whose output is compared to a fixed setpoint in a bistable trip device. These analog outputs may be cross-compared during power operation and their responses to power level changes observed. The bistable operation is tested by introducing a substitute current rather than the sensor output and observing trip action at the setpoint. Calibration of the sensors above the normal 100% power operating point is not possible during power operation; hence, the sensors may be calibrated during refueling outages by placing the sensors in the vicinity of an appropriate source.

Three scram signals, i.e., main steam isolation valve (MSIV) closure, turbine stop valve closure, and turbine control valve fast closure, have to be cycled independently and, therefore, meet IEEE 279 requirements.

The primary circuit breakers are inspected, maintained, and tested on a routine basis. This is accomplished without removing the generators, transformers, and transmission lines from service.

Transmission line protective relaying is tested on a routine basis. This is accomplished without removing the transmission lines from service. Generator, unit auxiliary transformer, and startup auxiliary transformer relaying are tested when the generator is off-line.

The 4160- and 600-V circuit breakers and associated equipment may be tested while individual equipment is shutdown. The circuit breakers may be placed in the "test" position and tested functionally. The breaker opening and closing may also be exercised. Circuit breakers and contactors for redundant or duplicated circuits may be tested in-service without interfering with plant operation.

Automatic transfers of 4160-V buses 1E, 1F, and 1G from startup transformers to emergency standby diesel generators are tested during the shutdown and startup of each unit to prove system operability.

The dc system has detectors to indicate when there is a ground existing on any portion of the system. A ground on one portion of the dc system will not cause any equipment to malfunction. The batteries are under continuous automatic charging and are inspected and checked on a routine basis while the unit is in service.

To verify that the emergency power system will properly respond within the required time limit when required, the following typical tests are performed periodically:

A. Manually initiated demonstration of the ability of the diesel generators to start and deliver power up to nameplate rating when operating in parallel with normal power sources. Normal plant operation is not affected. The duration of the test is long enough for the diesels to reach equilibrium operating temperatures.

B. Manual initiation of permanently installed testing devices demonstrates the ability of the control system to automatically start the diesel generator and restore power to vital equipment by simulating a loss-of-offsite power (LOSP) and/or loss-of-coolant accident (LOCA).

These tests include:

- Test for automatic transfer of emergency buses being supplied by the normal offsite power source to the alternate offsite power source.

- Test for automatically starting, connecting the diesel generators to the emergency bus, and loading the diesel generators upon loss of all offsite power sources.

- Test for automatically starting diesel generators upon a LOCA signal (drywell pressure high or reactor pressure vessel (RPV) water low level 1).

- Test for automatically starting, connecting diesel generators to the emergency buses, and sequentially loading the diesel generators upon a LOCA signal (drywell pressure high or RPV water low level 1) accompanied by an LOSP signal.

The ability to perform the above tests complies with the intent of General Design Criterion 18.

7.1.2 POWER GENERATION SYSTEMS

The power generation systems described in this section are as follows:

- Reactor manual control system (RMCS).

- Recirculation flow control system.

- Feedwater system control and instrumentation.

- Pressure regulator and turbine-generator control.

- Process computer.

- Process radiation monitoring subsystems (except main steam line and reactor building exhaust vent subsystems).

7.1.3 SAFETY FUNCTION

The major functions of the safety systems are summarized as follows:

A. Reactor Protection System

The RPS initiates an automatic reactor shutdown (scram) if monitored nuclear system variables exceed preestablished limits. This action limits fuel damage and system pressure and thus, restricts the release of radioactive material.

B. Primary Containment and Reactor Vessel Isolation Control System

This system initiates closure of various automatic isolation valves in response to out of limit nuclear system variables. The action provided limits the loss of coolant from the reactor vessel and contains radioactive material either inside the reactor vessel or inside the primary containment. The system responds to various indications of pipe breaks or radioactive material release.

C. Emergency Core Cooling System Control and Instrumentation

This section describes the arrangement of control devices for the high-pressure coolant injection (HPCI), automatic depressurization (ADS), core spray (CS), and low-pressure coolant injection (LPCI) subsystems.

D. Neutron Monitoring System

The NMS uses incore neutron detectors to monitor core neutron flux. The safety function of the NMS is to provide a signal to shut down the reactor when an overpower condition is detected. High average neutron flux is used as the overpower indicator. In addition, the NMS provides the required power level indication during planned operation.

E. Main Steam Radiation Monitoring System

Gamma sensitive radiation monitors are installed in the vicinity of the main steam lines just outside the primary containment. These monitors can detect a gross release of fission products from the fuel by measuring the gamma radiation coming from the steam lines. A high-radiation alarm signal is sent to the control room; the gland seal exhauster and the reactor water sample systems isolate; the mechanical vacuum pump is stopped; and the vacuum pump line is closed.

F. Refueling Interlocks

The refueling interlocks serve as a backup to procedural core reactivity control during refueling operation.

G. Reactor Vessel Instrumentation

The reactor vessel instrumentation monitors and transmits information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible.

H. Process Radiation Monitors Except Main Steam Line and Reactor Building Exhaust Radiation Monitoring Systems

A number of PRMs are provided on process liquid and gas lines to provide control and/or alarm in the event of radioactive material release from the site.

I. Low-Low Set Relief Logic System

The LLS relief logic system is designed to mitigate the postulated thrust load on the safety relief valve discharge lines (SRVDLs) and the effects of postulated high-frequency loads on the torus shell caused by subsequent actuations of the SRVs during a small-or-intermediate break LOCA.

J. Analog Transmitter Trip System

The ATTS consists of analog sensor/trip unit combinations which provide continual monitoring of critical parameters and provide inputs for the logic and sequencing of the RPS, primary containment isolation system, ECCS, reactor core isolation cooling, and LLS, as described in sections 7.2, 7.3, and 7.4. The ATTS does not perform any logic and sequencing internal to ATTS.

7.1.4 PLANT OPERATIONAL CONTROL

The major systems used to control the plant during planned operations are the following:

A. Reactor Manual Control System

This system allows the operator to manipulate the control rods and determine their positions. Various interlocks are provided in the control circuitry to avoid unnecessary protection system action resulting from operator error.

B. Recirculation Flow Control System

This system controls the speed of the two reactor recirculation pumps by varying the electrical frequency of the power supply for the pumps. By varying the coolant flowrate through the core, the power level may be changed. The system is arranged to allow for manual control (operator action).

C. Feedwater System Control and Instrumentation

This system regulates the feedwater flowrate so that proper reactor vessel water level is maintained. The feedwater system controller uses reactor vessel water level, main steam flow, and feedwater flow signals to regulate feedwater flow. The system is arranged to permit single element (level only), three element (level, steam flow, feed flow), or manual operation.

D. Pressure Regulator and Turbine-Generator Controls

The pressure regulator acts to maintain nuclear system pressure essentially constant, so that pressure-induced core reactivity changes are controlled. To maintain constant pressure, the pressure regulator adjusts the turbine control valves or turbine bypass valves. The turbine-generator controls act to maintain turbine speed constant, so that electrical frequency is maintained. The turbine-generator speed-load controls can initiate rapid closure of the turbine control valves (coincident with fast opening of the bypass valves) to prevent excessive turbine overspeed in case of loss of generator electrical load.

7.1.5 IDENTIFICATION OF AGENTS AND CONTRACTORS

General Electric, Bechtel, and Southern Company Services are the major contractors responsible for the design of Hatch Nuclear Plant-Unit 1 (HNP-1). Following is a summary of each contractor's responsibility:

A. The safety-related systems which actuate trip and ESF action and are supplied by General Electric Company are:

- RPS.
- Primary containment and reactor vessel isolation control system.
- ECCS control and instrumentation.
- NMS.
- Main steam line radiation monitoring system.
- LLS relief logic system control and instrumentation.

The condenser low-vacuum scram has been removed on HNP-1. There is no safety significance in this difference as reactor protection for the loss-of-condenser vacuum event is assured through the turbine trip scram resulting from turbine stop valve closure. The HNP-1 RPS is otherwise identical to that of earlier designs. Additionally, on HNP-1 the condenser low vacuum trip is arranged to close the MSIVs.

B. Bechtel had overall design responsibility for the engineered safeguards systems listed below:

- Main control room heating, ventilation, and air-conditioning (HVAC).

- Reactor building ventilation system radiation monitoring system.

- SGTS.

C. Southern Company Services had overall design responsibility for the engineered safeguards systems listed below:

- Plant service water (PSW) system.

- Residual heat removal service water (RHRSW) system.

- Standby ac power system.

- 125/250 V-dc power system.

A comprehensive comparison of the RPS with the design requirements of IEEE 279 has been assembled into a topical report, "Compliance of Protection Systems to Industry Criteria and General Electric BWR Nuclear Steam Supply System," (NEDO-10139). The results of this analysis indicate that the RPS which initiates reactor shutdown, and the CSC systems, which produce protective actions during and after a reactor accident, meet the design requirements of IEEE 279-1971.

The topical report illustrates the basis for the analysis and presents the designer's interpretation of the IEEE 279-1971 design requirements in those cases where an exact fit of the requirements to the intended protective function is not achieved.

The following radiation monitors, which provide automatic isolation of their respective process lines, are designed to be in full compliance with IEEE 279 requirements regarding redundancy, physical and electrical separation criteria, and seismic qualifications:

- Refueling floor ventilation exhaust duct.

- Reactor zone ventilation exhaust duct.

- Main steam line tunnel.

- Main control room air inlet duct.

D. The control systems supplied by General Electric Company that are functionally equivalent to those of the earlier licensed plants as described in the FSAR are:

- NMS.
- Refueling interlocks.
- RMCS.
- Reactor vessel instrumentation.
- Recirculation flow control system.
- Feedwater system control and instrumentation.
- Process radiation monitors.

E. While the reactor vessel instrumentation and the recirculation flow control system are basically the same for HNP-1 and the earlier design, the following differences may be noted in this area.

On the HNP-1 plant a "failure-to-scram" recirculation pump trip has been implemented. This involves the addition of reactor pressure sensors and auxiliary devices to provide a reactor recirculation pump trip in the event of high reactor pressure.

As the system is a backup to a scram system, no criteria exists as such for its design but the following considerations have been made: Added pressure switches and relays were purchased from manufacturers diverse other than the suppliers of the reactor protection equipment. These components were installed with the wiring methods and separation criteria of IEEE 279 devices and systems. The balance of installed and procured equipment is of standard commercial design.

It should be noted that systems identified in D are operational and control systems and should not be confused with protection systems identified in A, B, and C.

7.1.6 DEFINITIONS AND SYMBOLS

The complexity of the control and instrumentation systems requires the use of certain terminology and symbolism for clarification in the description of the protective systems.

Table 7.1-2 presents definitions applicable to instrumentation and control of protection systems.

Figure 7.1-1 illustrates the use of protection system, control, and instrumentation definitions.

Drawing no. S-15051 presents piping, instrumentation, and control symbols.

Drawing no. H-19900 presents logic symbols used on functional control diagrams.

TABLE 7.1-1

SAFETY-RELATED INSTRUMENTATION, CONTROL, AND ELECTRICAL SYSTEMS DIAGRAMS

Schematic Diagrams

Synchronizing and voltmeter
Diesel generator 1A, 1B, and 1C exciter
Emergency station service relays

Elementary Diagrams

Differential auxiliary relays
4160-V station service supply acb
PSW motor-operated valve
Diesel generator 1A heating and ventilation
Diesel generator 1B heating and ventilation
Diesel generator 1C heating and ventilation
Diesel generator 1A
Diesel generator 1B
Diesel generator 1C
Diesel miscellaneous equipment
PSW pumps
Emergency station service miscellaneous
Primary containment isolation system
SGTS
Main control room HVAC process radiation
Reactor building and refueling floor HVAC
RPS (scram)
Nuclear steam supply shutoff system (testability, condenser low-vacuum signal, MSIV interlock, removal of high water level trip, and interlocks on recirculation system)
HPCI system
Auto-blowdown system
CS system
RHR system (changed HPCI steam supply valve operators to air)
NMS - startup range
NMS - power range
PRMS (to be added are: 13 new monitors for turbine and reactor building monitor, standby gas monitor, off-gas treatment monitors)
Steam leak detection system
RPS - motor-generator set
ATTS

TABLE 7.1-2

DEFINITIONS APPLICABLE TO INSTRUMENTATION AND CONTROL OF PROTECTION SYSTEMS

Sensor - A sensor is that part of a channel used to detect variations in a measured variable.

Channel - A channel is an arrangement of one or more sensors and associated components used to evaluate plant variables and produce discrete outputs used in logic. A channel terminates and loses its identity where individual channel outputs are combined in logic.

Logic - Logic is that array of components which combines individual bistable output signals to produce decision outputs.

Trip - A trip is the change of state of a bistable device which represents the change from a normal condition.

Trip system - A trip system is that portion of a system encompassing one or more channels, logic, and bistable devices used to produce signals to the actuation device.

Setpoint - A setpoint is that value of the monitored variable which causes a channel trip.

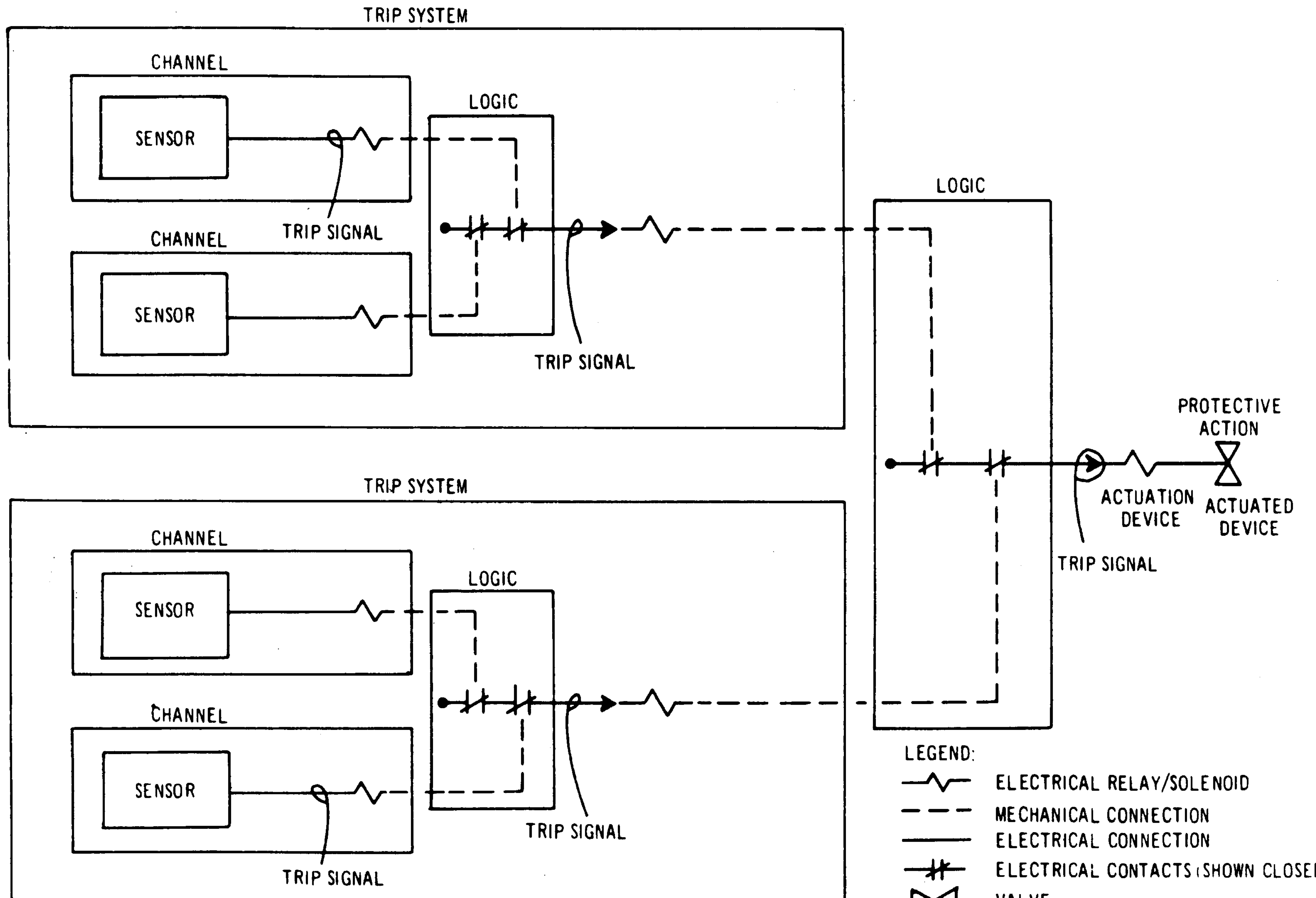
Actuation device - An actuation device is an electrical or electromechanical module controlled by an electrical decision signal and produces mechanical operation of one or more activated devices.

Activated device - An activated device is a mechanical component used to accomplish an action. An activated device is controlled by an actuation device.

Component - Components are items from which the system is assembled, i.e., resistors, capacitors, wires, connectors, transistors, switches, springs, pumps, valves, piping, heat exchangers, vessels, etc.

Module - A module is any assembly of interconnected components which constitutes an identifiable device, instrument, or piece of equipment.

Incident detection circuitry - Incident detection circuitry includes those trip systems which are used to sense the occurrence of an incident. Such circuitry is described and evaluated separately where the incident detection circuitry is common to several systems.



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USE OF PROTECTION SYSTEM CONTROL AND INSTRUMENTATION DEFINITIONS

FIGURE 7.1-1

7.2 REACTOR PROTECTION SYSTEM (RPS)

7.2.1 SAFETY OBJECTIVE

The RPS provides timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barriers (uranium dioxide sealed in cladding) and the nuclear system process barrier. Excessive temperature threatens to perforate the cladding or melt the uranium dioxide. Excessive pressure threatens to rupture the nuclear system process barrier. The RPS limits the uncontrolled release of radioactive material from the fuel and the nuclear system process barriers by terminating excessive temperature and pressure increases through the initiation of an automatic scram.

7.2.2 SAFETY DESIGN BASES

A. The RPS initiates with precision and reliability a reactor scram in time to prevent fuel damage following anticipated operational occurrences (AOOs).

B. The RPS initiates with precision and reliability a scram in time to prevent damage to the nuclear system process barrier as a result of internal pressure. Specifically, the RPS initiates a reactor scram in time to prevent nuclear system pressure from exceeding the nuclear system pressure allowed by applicable industry codes.

C. To limit the uncontrolled release of radioactive material from the fuel or the nuclear system process barrier, the RPS initiates with precision and reliability a reactor scram upon gross failure of either of these barriers.

D. To provide assurance that conditions which threaten the fuel or the nuclear system process barrier are detected with sufficient timeliness and precision, the RPS inputs are derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

E. To provide assurance that important variables are monitored with precision, the RPS responds correctly to the sensed variables over the expected range of magnitudes and rates of change.

F. To provide assurance that important variables are monitored with precision, an adequate number of sensors are provided for monitoring essential variables that have spatial dependence.

G. The following bases provide assurance that the RPS is designed with sufficient reliability.

    1. No single failure within the RPS prevents proper RPS action.

2. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability does not impair the ability of the RPS to respond correctly.

3. The system is designed for a high probability that when the required number of sensors for any monitored variable exceed the scram setpoint, the event results in an automatic scram and does not impair the ability of the system to scram as other monitored variables exceed their scram trip points.

4. Where a plant condition that requires a reactor scram can be brought on by failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more RPS channels designed to provide protection against the unsafe condition, the remaining portions of the RPS meet G1.

5. The power supply for the RPS is arranged so that loss of one supply neither causes nor prevents a reactor scram.

6. The system is designed so that, once initiated, a RPS action goes to completion. Return to normal operation after protection system action requires deliberate operator action.

7. There is sufficient electrical and physical separation between channels and between logics monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability of the system to respond correctly.

8. Earthquake ground motions do not impair the ability of the RPS to initiate a reactor scram.

H. The following bases are specified to reduce the probability that RPS operational reliability and precisions are degraded by operator error:

1. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables are under the control of plant operations personnel.

2. The means for manually bypassing logics, channels, or system components are under the control of the plant operator. If the ability to trip some essential part of the system has been bypassed, this fact is continuously annunciated in the main control room (MCR).

I. To provide the operator with means independent of the automatic scram functions to counteract conditions that threaten the fuel or nuclear system process barrier, it is possible for the plant operator to manually initiate a reactor scram.

J. The following bases are specified to provide the operator with the means to assess the condition of the RPS and to identify conditions that threaten the integrities of the fuel or nuclear system process barrier:

1. The RPS is designed to provide the operator with information pertinent to the operational status of the protection system.

2. Means are provided for prompt identification of channel and trip system responses.

K. It is possible to check the operational availability of each channel and logic.

7.2.3 DESCRIPTION

7.2.3.1 Identification

The RPS includes the motor-generator (M-G) power supplies, sensors, relays, bypass circuitry, trip units, and switches that cause rapid insertion of control rods (scram to shut down the reactor). It also includes outputs to the process computer system and annunciators. The process computer system and annunciators are not part of the RPS. Although scram signals are received from the neutron monitoring system (NMS), this system is treated as a separate nuclear safety system in section 7.15. The RPS is designed to meet the intent of the Institute of Electrical and Electronic Engineers (IEEE) Criteria for Nuclear Power Plant Protection Systems (IEEE 279-1971) as the following tabulation shows.

In this tabulation the safety design bases are compared with the IEEE 279-1971 design requirements and explanatory notes are made necessary. A detailed comparison of the RPS with the IEEE criteria is made in General Electric (GE) Topical Report NEDO-10139 (June 1970).

IEEE 279-1971 Design Requirement	Safety Design Bases
4.1	A, B, C, E
4.2	G1, G2, G3, G4
4.3	Note 1
4.4	Note 1
4.5	E, G5, G7, G8
4.6	G4, G7
4.7	G4

IEEE 279-1971 Design Requirement	Safety Design Bases
4.8	D, F
4.9	G2, H2, K
4.10	K (Note 2)
4.11	G2, H1, H2
4.12	G2, G3, H2
4.13	H2
4.14	G2, H1
4.15	E, G3 (Note 3)
4.16	G6
4.17	I (Note 4)
4.18	H1
4.19	J2 (Note 5)
4.20	J1 (Note 5)
4.21	Note 6

Note 1: The safety design bases do not specifically address the design requirement. However, the quality and the qualification test for the equipment and devices used in this system meet the intent of these design requirements as described elsewhere in this subsection.

Note 2: This design requirement is fully satisfied by the system design even though the safety design bases include only channel, logics, and trip systems.

Note 3: This design requirement is rarely used in a GE boiling water reactor due to a strong preference for fixed protective action setpoints.

Note 4: This design requirement is fully satisfied even though the safety design bases omit the minimum of equipment limitations.

Note 5: This design requirement is fully satisfied by the system design. Identification of channel trips is required by the safety design bases.

Note 6: Although not specifically addressed in the safety design bases, system repairs meet the design requirements.

7.2.3.2 Power Supply

Power to each of the two reactor protection trip systems is supplied, via a separate bus, by its own high-inertia ac M-G set. High inertia is provided by a flywheel. The inertia is sufficient to maintain voltage and frequency within 5% of rated values for at least 1.0 s following a total loss of power to the drive motor.

Alternate power is available to either RPS bus from an electrical bus that can receive standby electrical power. The alternate power switch prevents simultaneously feeding both buses from the same source. The switch also prevents paralleling a M-G set with the alternate supply. The backup scram valve solenoids receive dc power from the plant batteries. (See section 8.3 for details of the power supply system.)

7.2.3.3 Physical Arrangement

Instrument piping that taps into the reactor vessel is routed through the primary containment wall and terminates inside the secondary containment (reactor building). Reactor vessel pressure and water level information are sensed from this piping by instruments mounted both locally and on instrument racks in the reactor building. Valve position switches are mounted on valves from which position information is required. The sensors for RPS signals from equipment in the turbine building are mounted locally. The two M-G sets that supply power for the RPS are located in an area where they can be serviced during reactor operation. Cables from sensors and power cables are routed to two RPS cabinets in the control room, where the logic circuitry of the system is formed. Cables from the analog transmitter trip system (ATTS) sensors are routed to four ATTS RPS cabinets located in the control room before being routed to these RPS logic cabinets. One cabinet is used for each of the two trip systems. The logics of each trip system are isolated in separate bays in each cabinet. The RPS is designed as Seismic Class 1 equipment to assure a safe reactor shutdown during and after seismic disturbances.

RPS channels not located in Class 1 buildings are those from the turbine stop valves and turbine control valves. These channels are routed from the RPS cabinet located in the control building to the limit switches on the valves inside steel conduit. These conduits are marked to identify them as part of the RPS and no other circuits are run in these conduits.

The conduits are located under the turbine building shield floor at el 164 ft; thus, protection against physical damage is provided.

7.2.3.4 Logic

The basic logic arrangement of the RPS system is shown on drawings H-17791 and H-17792. Each trip system has three logics, as shown in figure 7.2-2. Two of the logics are used to produce automatic trip signals. The remaining logic is used for a manual trip signal. Each of the two logics used for automatic trip signals receives input signals from at least one channel for each monitored variable. Thus, two channels are required for each monitored variable to provide independent inputs to the logics of one trip system. At least four channels for each monitored variable are required for the logics of both trip systems.

As shown in figure 7.2-2, each pair of actuators associated with any one trip logic provides inputs into each of the actuator logics for the associated trip system. Thus, either of the two automatic logics associated with one trip system can produce a trip system trip. The logic is a one-out-of-two arrangement. To produce a scram, the actuator logics of both trip systems must be tripped. The overall logic of the RPS could be termed one-out-of-two-taken-twice.

7.2.3.5 Operation

To facilitate the description of the RPS, the two trip systems are called trip system A and trip system B. The automatic logics of trip system A are logics A1 and A2; the manual logic of trip system A is logic A3. Similarly, the logics for trip system B are logics B1, B2, and B3. The actuators associated with any particular logic are identified by the logic identity (such as actuators B2) and a letter (figure 7.2-2). Channels are identified by the name of the monitored variable and the logic identity with which the channel is associated (such as nuclear system high pressure channel B1).

During normal operation all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized. In contrast, however, trip bypass channels consist of normally-open contact networks.

There are two scram pilot valves and two scram valves for each control rod, arranged as shown on drawing no. H-19919 and HNP-2-FSAR figure 4.2-14 (sheet 2). Each scram pilot valve is solenoid operated, with the solenoids normally energized. The scram pilot valves control the air supply to the respective scram valves for each control rod. With either scram pilot valve energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for control rod drive (CRD) water. One of the scram pilot valves for each control rod is controlled by actuator logics A, the other valve by actuator logics B. There are two dc solenoid operated backup scram valves which provide a second means of controlling the air supply to the scram valves for all control rods. The dc solenoid for each backup scram valve is normally deenergized. The backup scram valves are energized (initiate scram) when both trip system A and trip system B are tripped.

The functional arrangement of sensors and channels that constitute a single logic is shown on drawing no. H-19933. Whenever a channel sensor contact opens, its sensor relay deenergizes, causing contacts in the logic to open. The opening of contacts in the logic deenergizes its actuators. When deenergized, the actuators open contacts in all the actuator logics for that trip system. This action results in deenergizing the scram pilot valve solenoids associated with that trip system (one scram pilot valve solenoid for each control rod). Unless the other scram pilot valve solenoid for each rod is deenergized, the rods are not scrammed. If a trip then occurs in any of the logics of the other trip system, the remaining scram pilot valve solenoid for each rod is deenergized, venting the air pressure from the scram valves, and allowing CRD water to act on the CRD piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is vented into a scram discharge volume. Drawing no. H-19919 and HNP-2-FSAR figure 4.2-14 (sheet 2), show that when the solenoid for each backup scram valve is energized, the backup scram valves vent the air supply for the scram valves; this action initiates insertion of every control rod regardless of the action of the scram pilot valves.

A scram can be manually initiated. There are two scram buttons, one for logic A3 and one for logic B3. Depressing the scram button on logic A3 deenergizes actuators A3 and opens corresponding contacts in actuator logics A. A single trip system trip is the result. To cause a manual scram, the buttons for both logic A3 and logic B3 must be depressed. The manual scram buttons are close enough to permit one hand motion to cause a scram. By operating the manual scram button for one manual logic at a time, followed by reset of that logic, each trip system can be tested for manual scram capability. It is also possible for the plant operator to scram the reactor by interrupting power to the RPS. This can be done by operating power supply breakers.

To restore the RPS to normal operation following any single trip system trip or scram, the actuators must be manually reset. Reset is possible only after a delay of 10 s and if the conditions that caused the trip or scram have been cleared, and is accomplished by operating switches in the control room. Drawing no. H-19934, shows the functional arrangement of reset contacts for trip system A.

Whenever a RPS sensor trips, it lights a printed red annunciator window, common to all the channels for the variable, on the reactor control panel in the control room to indicate the out-of-limit variable. Each trip system lights a red annunciator window indicating the trip system which has tripped. A RPS channel trip also initiates an audible alarm which can be silenced by the operator. The annunciator window lights latch in until manually reset; reset is not possible until the condition causing the trip has been cleared. A computer display identifies each tripped channel; however, the physical positions of RPS relays may also be used to identify the individual sensor that tripped in a group of sensors monitoring the same variable. The location of alarm windows provides the operator with the means to quickly identify the cause of RPS trips and to evaluate the threat to the fuel or nuclear system process barrier.

To provide the operator with the ability to analyze an AOO during which events occur too rapidly for direct operator comprehension, all RPS trips are logged chronologically by the process computer system. Use of the process computer is not required for plant safety, and information provided is in addition to that immediately available from other annunciators and data displays. The logging of trips is of particular usefulness in routinely verifying the proper operation of pressure, level, and valve position switches/trip units as trip points are passed during startups, shutdowns, and maintenance operations.

RPS inputs to annunciators, recorders, and the computer are arranged so that no malfunction of the annunciating, recording, or computing equipment can functionally disable the RPS. Signals directly from the RPS sensors are not used as inputs to annunciating or data logging equipment. Relay contact isolation is provided between the primary signal and the information output.

7.2.3.6 Scram Functions and Bases for Trip Settings

The following discussion covers the functional considerations for the variables or conditions monitored by the RPS. Table 7.2-1 lists the preliminary specifications for instruments providing signals for the system.

A. NMS Trip

To provide protection for the fuel against high heat generation rates, neutron flux and thermal-hydraulic instabilities are monitored and used to initiate a reactor scram. The NMS setpoints and their bases are discussed in section 7.5, Neutron Monitoring System.

B. Reactor High Pressure

High pressure within the nuclear system poses a direct threat of rupture to the nuclear system process barrier. A reactor pressure increase while the reactor is operating compresses the steam voids and results in a positive reactivity insertion causing increased core heat generation that could lead to fuel failure and system overpressurization. A scram counteracts a pressure increase by quickly reducing the core fission heat generation.

The reactor high-pressure scram setting is chosen slightly above the reactor vessel maximum normal operation pressure to permit normal operation without spurious scrams yet provide a wide margin to the maximum allowable reactor pressure. The location of the pressure measurement, as compared to the location of highest reactor pressure during transients, was also considered in the selection of the reactor high-pressure scram setting. The reactor high-pressure scram works in conjunction with the pressure relief system in preventing reactor pressure from exceeding the maximum allowable pressure. This same reactor high-pressure scram setting also protects the core from exceeding thermal-hydraulic limits as a result of pressure increases for some events that occur when the reactor is operating at less than rated power and flow.

C. Reactor Pressure Vessel (RPV) Water Level 3

Low water level in the reactor vessel indicates that the reactor is in danger of being inadequately cooled. The effect of a decreasing water level while the reactor is operating at power is to decrease the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. Should water level decrease too far, fuel damage could result as steam forms around fuel rods. A reactor scram protects the fuel by reducing the fission heat generation within the core.

The RPV water level 3 scram setting was selected to prevent fuel damage following the AOOs caused by single equipment malfunction or single operator errors that result in a decreasing reactor vessel water level. Specifically, the scram setting is chosen far enough below normal operational levels to avoid spurious scrams but high enough above the top of the active fuel to assure that enough water is available to account for evaporation losses and displacements of coolant following the most severe AOO involving a level decrease. The selected scram setting was used in the development of thermal-hydraulic limits, which set operational limits on the thermal power level for various coolant flowrates.

D. Turbine Stop Valve Closure

Closure of the turbine stop valves with the reactor at power can result in a significant addition of positive reactivity to the core as the reactor pressure rise collapses steam voids. The turbine stop valve closure scram, which initiates a scram earlier than either the NMS or reactor high pressure, is required to provide a satisfactory margin below core thermal-hydraulic limits for this category of AOOs. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods.

Although the reactor high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the reactor pressure limit.

The turbine stop valve closure scram setting is selected to provide the earliest positive indication of valve closure.

E. Turbine Control Valve Fast Closure

With the reactor and turbine-generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as reactor pressure rises. The turbine control valve fast closure scram, which initiates a scram earlier than either the NMS or reactor high pressure, is required to provide a satisfactory margin to core thermal-hydraulic limits for this category of AOOs. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods. Although the reactor high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the reactor, the turbine control valve fast closure scram provides additional margin to the reactor pressure limit. The turbine control valve fast closure scram setting is selected to provide timely indication of turbine control valve fast closure. The system is designed to meet IEEE 279 standards with the single exception that it is located on a non-Seismic Class 1 primary structure.

F. Main Steam Line Isolation

The main steam isolation valve (MSIV) closure scram is provided to limit the release of fission products from the nuclear system. Automatic closure of the MSIVs is initiated upon conditions indicative of a steam line break. Immediate shutdown of the reactor is appropriate in such a situation. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The trip logic allows functional testing of main steam line isolation trip channels with one steam line isolated.

G. Scram Discharge Volume High Water Level

The scram discharge volume receives the water displaced by the motion of the CRD pistons during a scram. Should the scram discharge volume fill up with water to the point where not enough space remains for the water displaced during a scram, control rod movement would be hindered in the event a scram were required. To prevent this situation, the reactor is scrammed when the water level in the discharge volume attains a value high enough to verify that the volume is filling up, yet low enough to ensure that the remaining capacity in the volume can accommodate a scram.

H. Primary Containment High Pressure

High pressure inside the primary containment could indicate a break in the nuclear system process barrier. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and to reduce the addition of energy from the core to the coolant. The primary containment high-pressure scram setting is selected to be as low as possible without inducing spurious scrams.

I. Manual Scram

To provide the operator with means to shut down the reactor, pushbuttons are located in the MCR that initiate a scram when actuated by the operator.

J. Mode Switch in SHUTDOWN

The mode switch provides appropriate protective functions for the condition in which the reactor is to be operated. The reactor is shut down with all control rods inserted when the mode switch is in SHUTDOWN. To enforce the condition defined for the SHUTDOWN position, placing the mode switch in the SHUTDOWN position initiates a reactor scram. This scram is not considered a protective function because it is not required to protect the fuel or nuclear system process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short time delay, permitting a scram reset to restore the normal valve lineup in the control rod drive hydraulic system (CRDHS).

K. Turbine Hydraulic Control System Low-Pressure Scram Trip Setting

The turbine hydraulic control system operates using high-pressure oil. There are several points in this oil system where a loss of oil pressure could result in a fast closure of the turbine control valves. This fast closure of the turbine control valves does not result in a turbine control valve fast closure scram trip since failure of the oil system would not result in the fast closure solenoid valves being actuated. The turbine control valve fast closure scram trip is initiated from auxiliary switches on the fast acting solenoid. For a turbine control valve fast closure, the core would be protected by the average power range monitor (APRM) flux scrams and high reactor pressure scrams. However, to provide the same margins as provided by the turbine control valves fast closure scram trip, a scram has been added to the RPS which senses failure of control oil pressure to the turbine control system. This is an anticipatory scram and results in reactor shutdown before any significant increase in pressure or neutron flux occurs. The transient response is very similar to that resulting from the generator load rejection. This scram is bypassed below ~ 27.6% power level as measured by turbine first stage pressure.

7.2.3.7 Mode Switch

A conveniently located, multiposition, keylock mode switch is provided to select the necessary scram functions for various plant conditions. In addition to selecting scram functions from the proper sensors, the mode switch provides appropriate bypasses. The mode switch also interlocks such functions as control rod blocks and refueling equipment restrictions, which are not considered here as part of the RPS. The switch itself is designed to provide separation between the two trip systems. The mode switch positions and their related scram functions are as follows:

- SHUTDOWN - Initiates a reactor scram; bypasses main steam line isolation scram.
- REFUEL - Selects NMS scram for low neutron flux level operation (section 7.5, Neutron Monitoring System); bypasses main steam line isolation scram.
- STARTUP/HOT STANDBY - Selects NMS scram for low neutron flux level operation (section 7.5); bypasses main steam line isolation scram.
- RUN - Selects NMS scram for power range operation (section 7.5).

7.2.3.8 Scram Bypasses

A number of scram bypasses are provided to account for the varying protection requirements depending on reactor conditions and to allow for instrument service during reactor operations.

Some bypasses are automatic, others are manual. All manual bypass switches are in the MCR, under the direct control of the plant operator. The bypass status of trip system components is continuously indicated in the MCR.

Automatic bypass of the scram trips from main steam line isolation is provided when the mode switch is not in the RUN position.

The bypass allows reactor operations at low power with the main steam lines isolated. This condition exists during startups and certain reactivity tests during refueling.

The scram initiated by placing the mode switch in SHUTDOWN is automatically bypassed after a time delay of 2 to 10 s. The bypass is provided to restore the CRDHS valve lineup to normal. An annunciator in the MCR indicates the bypassed condition. An automatic bypass of the turbine control valve fast closure (turbine hydraulic control system low-pressure) scram, and turbine stop valve closure scram is effected whenever the turbine first stage pressure is less than a preset fraction of its rated value. Closure of these valves from such a low initial power level does not constitute a threat to the integrity of any barrier to the release of radioactive material. Bypasses for the NMS channels are described in section 7.5. A manual key lock switch located in the control room permits the operator to bypass the scram discharge volume high-level scram trip if the mode switch is in SHUTDOWN or REFUEL. This bypass allows the operator to reset the RPS, so that the system is restored to operation while the operator drains the scram discharge volume. In addition to allowing the scram relays to be reset, actuating the bypass initiates a control rod block. Resetting the trip actuators opens the scram discharge volume vent and drain valves. An annunciator in the MCR indicates the bypass condition.

7.2.3.9 Instrumentation

Channels providing inputs to the RPS are not used for automatic control of process systems, thus the operations of protection and process systems are separated. The RPS instrumentation shown on drawing no. H-19935, is discussed as follows:

A. The NMS instrumentation is described in section 7.5. Figure 7.2-3 clarifies the relationship between NMS channels, NMS logic, and the RPS logic. The NMS channels are considered part of the NMS. The NMS logic is considered part of the RPS. As shown in figure 7.2-3 of the HNP-2-FSAR, four NMS logics are associated with each trip system of the RPS. Each RPS logic receives input from two NMS logics.

   Each NMS logic receives signals from one intermediate range monitor (IRM) channel and one APRM voter channel. The position of the mode switch determines which input signals affect the output signal from the logic. The arrangement of NMS logics is such that the failure of any one logic cannot prevent the initiation of a high neutron flux scram.

B. Reactor pressure is measured at two locations. A pipe from each location is routed through the primary containment and terminates in the reactor building. Two locally rack-mounted transmitters monitor the pressure in each pipe. Cables from these transmitters are routed to the associated trip units located in the MCR. The two pair of transmitters/trip units are physically separated. Each trip unit provides a high-pressure signal to one channel. The trip units are arranged so that each pair provides an input to trip system A and trip system B, as shown in figure 7.2-4. The reactor pressure instrumentation mentioned above is part of the analog transmitter trip system (ATTS), which is discussed in section 7.18.

C. RPV water level 3 signals are initiated from non-indicating-type differential pressure transmitters which sense the difference between the pressure due to a reference column of water and the pressure due to the actual water level in the vessel. Cables from these transmitters are routed to associated trip units in the MCR. The transmitters are arranged in pairs in the same way as the reactor high-pressure transmitters (figure 7.2-4). Two instrument lines attached to taps, one above and one below the water level, on the reactor vessel are required for the differential pressure measurement for each pair of transmitters. The two pair of lines terminate outside the primary containment and inside the reactor building; they are physically separated from each other and tap off the reactor vessel at widely separated points. The RPS pressure transmitters, as well as instruments for other systems, sense pressure and level from these same pipes. This RPV water level instrumentation is part of ATTS, which is discussed in section 7.18.

D. Turbine stop valve closure inputs to the RPS are from valve stem position switches mounted on the four turbine stop valves. Each of the double-pole, single-throw switches is arranged to open before the valve is more than 10% closed to provide an early positive indication of closure. As shown in figure 7.2-5, the logic is arranged so that closure of three or more valves initiates a scram. The recirculation pump trip (RPT) system, which aids the scram system, is discussed in HNP-2 FSAR subsection 7.6.10.

E. Turbine control valve fast closure inputs to the RPS are from pressure switches on each of the electrohydraulic control (EHC) oil lines to the main control valves. These pressure switches measure the EHC oil pressure which decreases rapidly upon a generator load rejection and just prior to fast closure of the main control valves. The pressure switches provide input signals to the RPS using the logic arrangement as shown in figure 7.2-4. The RPT system which aids the scram system is discussed in HNP-2 FSAR subsection 7.6.10.

F. MSIV closure inputs to the RPS are from valve stem position switches mounted on the eight MSIVs. Each of the double-pole, single-throw switches is arranged to open before the valve is more than 10% closed to provide the earliest positive indication of closure. Either of the two trip channels associated with one isolation valve can signal valve closure. To facilitate the description of the logic arrangement, the position sensing channels for each valve are identified and assigned to RPS trip logics as follows.

Valve Identification	Position Sensing Channels	Trip Channel Relays	Trip Logic Assignment
Main steam line A, inboard valve	FO22A (1) & (2)	A, B	A1, B1
Main steam line A, outboard valve	FO28A (1) & (2)	A, B	A1, B1
Main steam line B, inboard valve	FO22B (1) & (2)	E, D	A1, B2
Main steam line B, outboard valve	FO28B (1) & (2)	E, D	A1, B2
Main steam line C, inboard valve	FO22C (1) & (2)	C, F	A2, B1
Main steam line C, outboard valve	FO28C (1) & (2)	C, F	A2, B1
Main steam line D, inboard valve	F022D (1) & (2)	G, H	A2, B2
Main steam line D, outboard valve	FO28D (1) & (2)	G, H	A2, B2

Thus, each trip logic receives signals from the valves associated with two steam lines (figure 7.2-6). The arrangement of signals within each trip logic requires that at least one valve in each of the steam lines associated with that trip logic close to cause a trip of that trip logic. For example, closure of the inboard valve of steam line A and the outboard valve of steam line C causes a trip of logic B1. This in turn causes trip system B to trip. No scram occurs because no trips occur in trip system A. In no case does closure of two valves or isolation of two steam lines cause a scram due to valve closure. Closure of one valve in three or four of the steam lines causes a scram.

In the extremely unlikely event that the reactor was operating with only two steam lines, (the remaining two presumably isolated) 10% closure of a further MSIV would result in a reactor scram. Thus, any test involving valve movement is precluded.

With one steam line isolated, closure tests of the remaining valves, one at a time, can be made. This flexibility is adequate to meet all prescribed test requirements of this nature.

Wiring for the position-sensing channels from one position switch is physically separated in the same way that wiring to duplicate sensors on a common process tap is separated. The wiring for position-sensing channels feeding the different trip logics of one trip system are also separated.

The MSIV closure scram function is effective when the reactor mode switch is in the RUN position.

The effects of the logic arrangement and separation provided for the MSIV closure scram are as follows:

- Closure of one valve for test purposes with one steam line already isolated without causing a scram due to valve closure.
- Automatic scram upon isolation of three or four steam lines.
- No single failure can prevent an automatic scram required for fuel protection due to MSIV closure.

G. Scram discharge volume high water level inputs to the RPS are from four nonindicating float switches and four redundant and diverse thermal probes located in the reactor building. Cables are routed from the thermal probes to switches located in the MCR. Each switch provides an input into one channel (figure 7.2-4). The switches are arranged in pairs so that no single event prevents a reactor scram due to scram discharge volume high water level. The trip point for these switches cannot be adjusted significantly without physically cutting the switch or thermal probe out of the scram discharge volume and rewelding it at a different level. With the scram setting as listed in table 7.2-1, a scram is initiated when sufficient capacity remains to accommodate a scram. Both the amount of water discharged and the volume of air trapped above the free surface during a scram were considered in selecting the trip setting.

H. Primary containment pressure is monitored by four nonindicating pressure transmitters which are mounted locally outside the drywell in the reactor building. Cables from these transmitters are routed to associated trip units located in the MCR. Each trip unit provides an input to one channel (figure 7.2-4). Pipes that terminate in the secondary containment (reactor building) connect the transmitters with the drywell interior. The transmitter/trip units are grouped in pairs, physically separated and electrically connected to the RPS so that no single event prevents a scram due to primary containment high pressure. This instrumentation is part of ATTS, which is discussed in section 7.18.

I. The mode switch is used for automatic bypass of the main steam line isolation trip.

J. Four turbine first-stage pressure switches are provided to initiate the automatic bypass of the turbine control valve fast closure and turbine stop valve closure scrams when the first-stage pressure is below some preset fraction of rated pressure corresponding to ~ 27.6% of rated steam flow.

Channel and logic relays are fast response, high reliability relays. All RPS relays are selected so that the continuous load does not exceed 50% of the continuous duty rating. Component electrical characteristics are selected so that the system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is < 50 ms. The time requirements for control rod movement are discussed in HNP-2-FSAR subsection 4.2.3, Reactivity Control system.

Sensing elements are equipped with enclosures so that they can withstand conditions that may result from a steam or water line break long enough to perform satisfactorily.

To gain access to the calibration and trip setting controls, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected.

The scram pilot valve solenoids are powered from eight actuator logic circuits, four circuits from trip system A and four from trip system B. The four circuits associated with any one trip system are run in separate conduits. One actuator logic circuit from each trip system may be run in the same conduit; wiring for the two solenoids associated with any one control rod may be run in the same conduit.

7.2.4 SAFETY EVALUATION

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrities of the fuel barrier and the nuclear system process barrier. The objective of HNP-2-FSAR chapter 15, Safety Analysis, is to identify and evaluate events that challenge the fuel barrier and nuclear system process barrier. Chapter 15 provides the methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are evaluated.

Design procedures select tentative scram trip settings that are far enough above or below normal operating levels that spurious scrams and operating inconvenience are avoided; it is then verified by analysis that the reactor fuel and nuclear system process barriers are protected, as required by the basic objective. In all cases, the specific scram trip point selected is not the only value of the trip point which results in no damage to either the fuel or the nuclear system process barrier; trip setting selection is based on operating experience and constrained by the safety design basis.

The scrams initiated by NMS variables, reactor high pressure, turbine stop valve closure, turbine control valve fast closure, and RPV water level 3 are sufficient to prevent fuel damage following AOOs. Specifically, these scram functions initiate a scram in time to prevent the core from exceeding the thermal-hydraulic safety limit during AOOs.

The scram initiated by reactor high pressure, in conjunction with the pressure relief system, is sufficient to prevent damage to the nuclear system process barrier as a result of internal pressure. For turbine-generator trips, the stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the reactor pressure safety limit than the high-pressure scram. HNP-2-FSAR chapter 15 identifies and evaluates accidents and AOOs that result in reactor pressure increases; in no case does pressure exceed the reactor safety limit.

The scram initiated by the NMS, MSIV closure, and reactor vessel water level 3 satisfactorily limits the radiological consequences of gross failure of the fuel or nuclear system process barriers. HNP-2-FSAR chapter 15 evaluates gross failures of the fuel and nuclear system process barriers; in no case does the release of radioactive material to the environs result in exposures which exceed the guideline values of published regulations.

Neutron flux (the NMS variable) is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in section 7.5. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities. The following discussion evaluates these subjects.

In terms of protection system nomenclature, the RPS is a one-out-of-two-taken-twice system (one of two times two). Theoretically, its reliability is slightly higher than a two-out-of-three system and slightly lower than a one-out-of-two system. However, since the differences are slight, they can, in a practical sense, be neglected. The advantage of the dual trip system arrangement is that it can be tested thoroughly during reactor operation without causing a scram. This capability for a thorough testing program, which contributes significantly to increased reliability, is not possible for a one-out-of-two system.

The use of an independent channel for each trip logic allows the system to sustain any channel failure without preventing other sensors monitoring the same variable from initiating a scram. A single sensor or channel failure causes a single trip system trip and actuates alarms that identify the trip. The failure of two or more sensors or channels would cause either a single trip system trip (if the failures were confined to one trip system) or a reactor scram (if the failures occurred in different trip systems). Any intentional bypass, maintenance operation, calibration operation, or test, all of which result in a single trip system trip, leaves at least two channels per monitored variable capable of initiating a scram by causing a trip of the remaining trip system. The following measures have been taken to improve the redundancy of safety-related circuits:

A. The APRM bypass switches are fitted with metal barriers separating the switch sections plus a downstream electrical interlock which provides electrical isolation upon selection.

B. The IRM bypass switches are treated in the same manner as the APRM switches.

C. The RPS scram reset switch is fitted with metal barriers separating the switch sections plus an enclosure can around the switch.

D. The RPS discharge volume scram bypass switch is treated in the same manner as the RPS scram reset switch.

The resistance to spurious scrams contributes to plant safety, because unnecessary cycling of the reactor through its operating modes would increase the probability of error or actual failure.

An actual condition in which an essential monitored variable exceeds its scram trip point is sensed by at least two independent sensors in each trip system. Because only one trip logic must trip in each trip system to initiate a scram, the arrangement of a monitored variable channel in each of the two trip logics per trip system provides assurance that a scram will occur as any monitored variable exceeds its scram setting.

Each control rod is controlled as an individual unit. A failure of the controls for one rod would not affect other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required.

Sensors, channels, and trip logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system.

Failure of either RPS M-G set would result, at worst, in a single-trip system trip. Alternate power is available to the RPS buses. A complete, sustained loss of electrical power to both buses would result in a scram, delayed by the M-G set flywheel inertia.

The environmental conditions in which the instruments and equipment of the RPS must operate are considered in setting the environmental specification. For the instruments located in the reactor or turbine buildings, the specifications are based on the worst expected ambient conditions in which the instruments must operate. The RPS components which are located inside the primary containment and which must function in the environment resulting from a break of the nuclear system process barrier inside the primary containment are the temperature compensating columns and condensing chambers. Special precautions are taken to ensure satisfactory operability after the accident. The temperature compensating columns and condensing chambers are similar to those that have successfully undergone qualification testing in connection with other projects.

Safe shutdown of the reactor during earthquake ground motion is assured by the design representing a Class 1 system and the fail-safe characteristics of the system. The system only fails in a direction that causes a reactor scram when subjected to extremes of vibration and shock.

To ensure that the RPS remains functional, the number of operable channels for the essential monitored variable are maintained at or above the minimums given in tables 7.2-2 and 7.2-3. The minimums apply to any untripped trip system; a tripped trip system may have any number of inoperable channels. Because reactor protection requirements vary with the mode in which the reactor operates, the tables show different functional requirements for the RUN and STARTUP modes. These are the only modes where more than one control rod can be withdrawn from the fully inserted position.

Calibration and test controls for the NMS and ATTS trip units are located in the MCR and are, because of their physical location, under direct physical control of the plant operator. Calibration and test controls for pressure switch/transmitters, level switch/transmitters, and valve position switches are located in the turbine building, reactor building, and primary containment. To gain access to the setting controls on each switch/transmitter, a cover plate or sealing device must be removed. The plant operator is responsible for granting access to the setting controls to properly qualified plant personnel for the purpose of testing or calibration adjustment.

7.2.5 INSPECTION AND TESTING

The RPS can be tested during reactor operation by five separate tests. The first of these is the manual trip actuator test. By depressing the manual scram button for one trip system, the manual trip logic actuators are deenergized, opening contacts in the actuator logics. After resetting the first trip system, the second trip system is tripped with the other manual scram button. The total test verifies the ability to deenergize all eight groups of scram pilot valve solenoids by using the manual scram pushbutton switches. Scram group indicator lights verify that the actuator contacts have opened.

The second test is the automatic actuator test which is accomplished by operating, one at a time, the keylocked test switches for that logic causing the associated actuator contacts to open. The test verifies the ability of each automatic trip logic to deenergize the actuator logics associated with the parent trip system. The actuator and contact action can be verified by observing the physical position of these devices.

The third test includes calibration of the NMS by means of simulated inputs from calibration signal units. Section 7.3 describes the calibration procedure.

The fourth test is the single rod scram test which verifies capability of each rod to scram. It is accomplished by operation of toggle switches on the protection system operations panel. Timing traces can be made for each rod scrammed. If the test is conducted in Mode 1 or 2 below the Technical Specification low power setpoint for the rod worth minimizer, a physics review is conducted prior to the test to assure that the rod pattern during scram testing does not create a rod of excessive reactivity worth. This physics review may involve the special CRDA analyses described in the Bases for Technical Specification 3.10.7.

The fifth test involves applying a test signal to each RPS channel in turn and observing that the associated automatic trip actuators are deenergized. This test also verifies the electrical independence of the channel circuitry. The test signals can be applied to the process type sensing instruments (pressure and differential pressure) through calibration taps.

RPS response times are first verified during preoperational testing and may be verified thereafter by similar test. The elapsed times from sensor trip to each of the following events is measured.

- Channel relay deenergized.

- Trip actuators deenergized.

The logging function of the process computer verifies the proper operation of many sensors during plant startups and shutdowns. MSIV position switches and turbine stop valve position switches can be checked in this manner. The verification provided by the logging function is not considered in the selection of test and calibration frequencies and is not required for plant safety.

TABLE 7.2-1

REACTOR PROTECTION SYSTEM SCRAM SETTINGS

Function	Instrument	Trip Setting
NMS scram	See section 7.5.	
RPV steam dome pressure - high	Pressure transmitter/ trip unit	(a)
RPV water level - low (level 3)[b]	Differential pressure transmitter/trip unit	(a)
Turbine stop valve closure	Position switch	(a)
Turbine control valve fast closure	Pressure switch	(a)
MSIV closure	Position switch	(a)
Scram discharge volume water level - high	Level switch	(a)
	Resistance temperature detector	(a)
Drywell pressure - high	Pressure transmitter/ trip unit	(a)

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 instrument setpoint index for actual setpoints.
b. Referenced to instrument zero.

TABLE 7.2-2

REACTOR PROTECTION SYSTEM
MINIMUM NUMBER OF OPERABLE CHANNELS REQUIRED FOR
FUNCTIONAL PERFORMANCE - STARTUP MODE

Channel Description	Normal No. of Operable Channels per Trip System	Minimum No. of Operable Channels Required per Untripped Trip System to Maintain Functional Performance[a]
NMS (APRM)	4	3
NMS (two-out-of four voter)	2	2
NMS (IRM)	4	3
RPV pressure - high	2	2
RPV water level – low level 3	2	2
Each MSIV position	0 (bypassed)	0
Scram discharge volume water level - high		
- Float switches	2	2
- Thermal level switches	2	2
Primary containment pressure - high	2	2
Manual scram	1	1

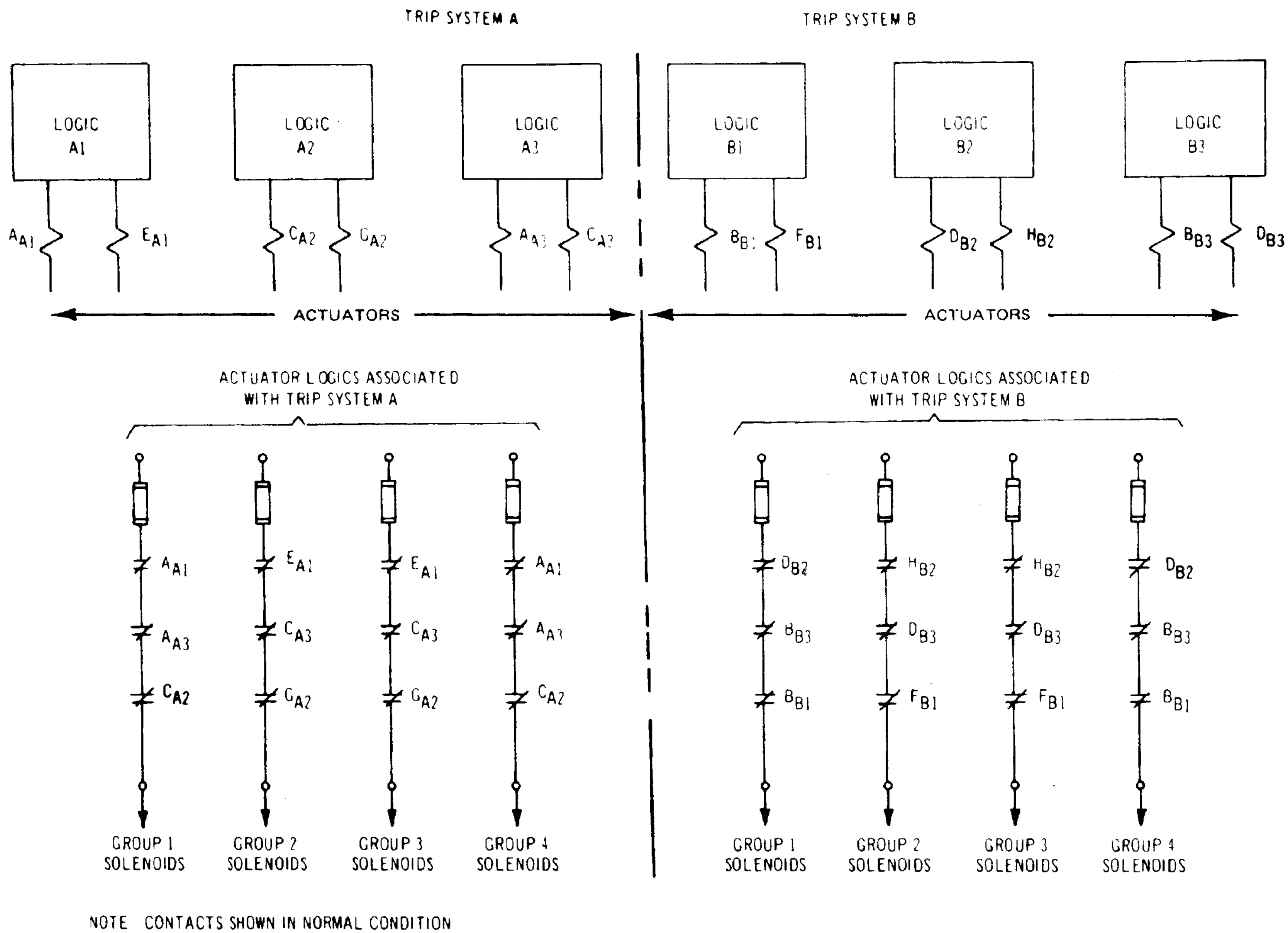
a. During testing of sensors, the channel should be tripped whenever the initial state of the sensor is not essential to the test. If the number of operable channels cannot be met for one of the trip systems, the inoperable channel(s) or the associated trip system shall be tripped.

TABLE 7.2-3

REACTOR PROTECTION SYSTEM
MINIMUM NUMBER OF OPERABLE CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE - RUN MODE

Channel Description	Normal No. of Operable Channels per Trip System	Minimum No. of Operable Channels Required per Untripped Trip System to Maintain Functional Performance[a]
NMS (APRM)	4	3
NMS (two-out-of four voter)	2	2
RPV high pressure	2	2
RPV water level - low level 3	2	2
Each turbine stop valve position	4	4
Each turbine control valve	2	2
Turbine first-stage pressure (bypass channel)	2	2
Each MSIV position	4	4
Scram discharge volume water level - high		
- Float switches	2	2
- Thermal level switches	2	2
Primary containment Pressure - high	2	2
Manual scram	1	1

a. During testing of sensors, the channel should be tripped whenever the initial state of the sensor is not essential to the test. If the number of operable channels cannot be met for one of the trip systems, the inoperable channel(s) or the associated trip system shall be tripped.



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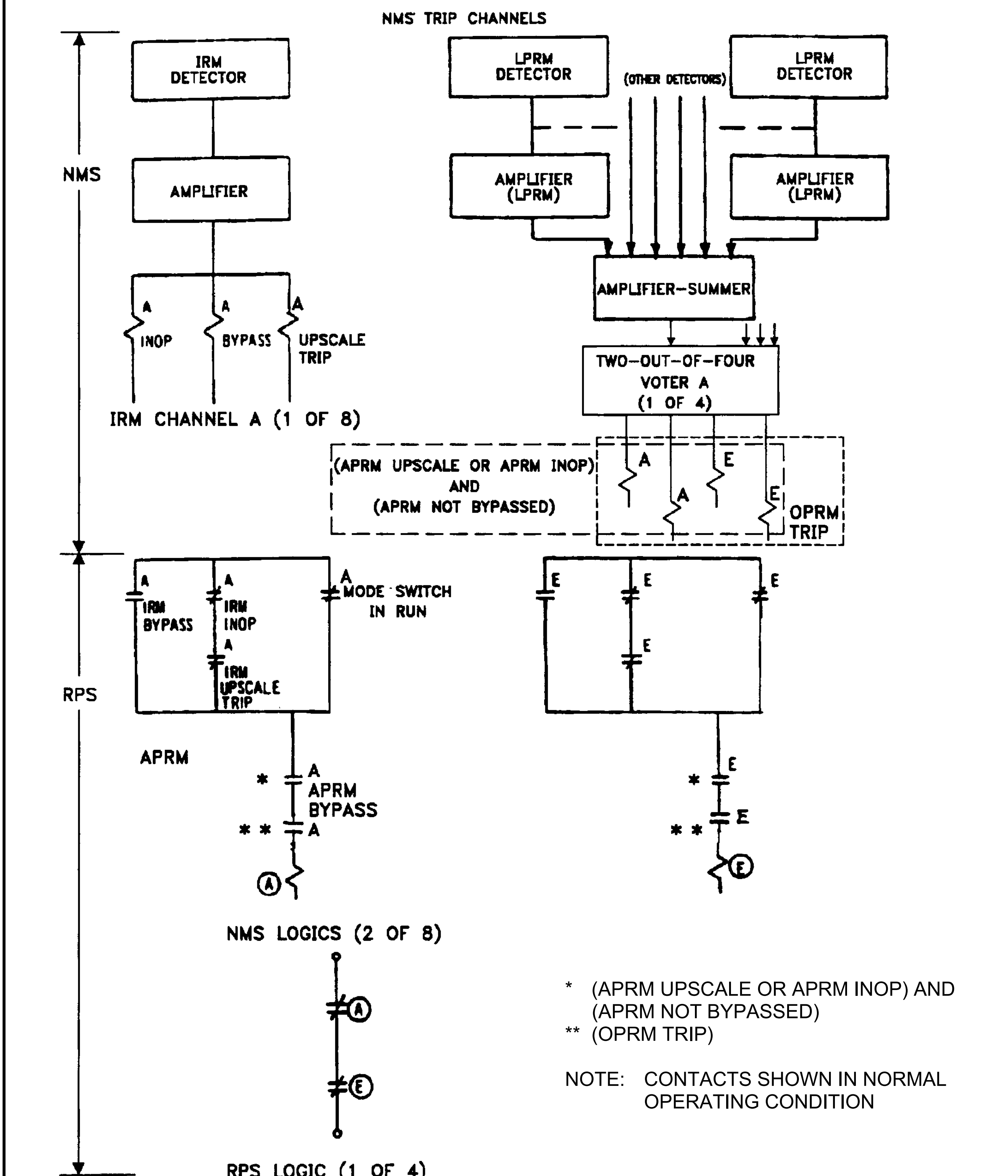
SCHEMATIC DIAGRAM OF ACTUATORS AND ACTUATOR LOGICS

FIGURE 7.2-2



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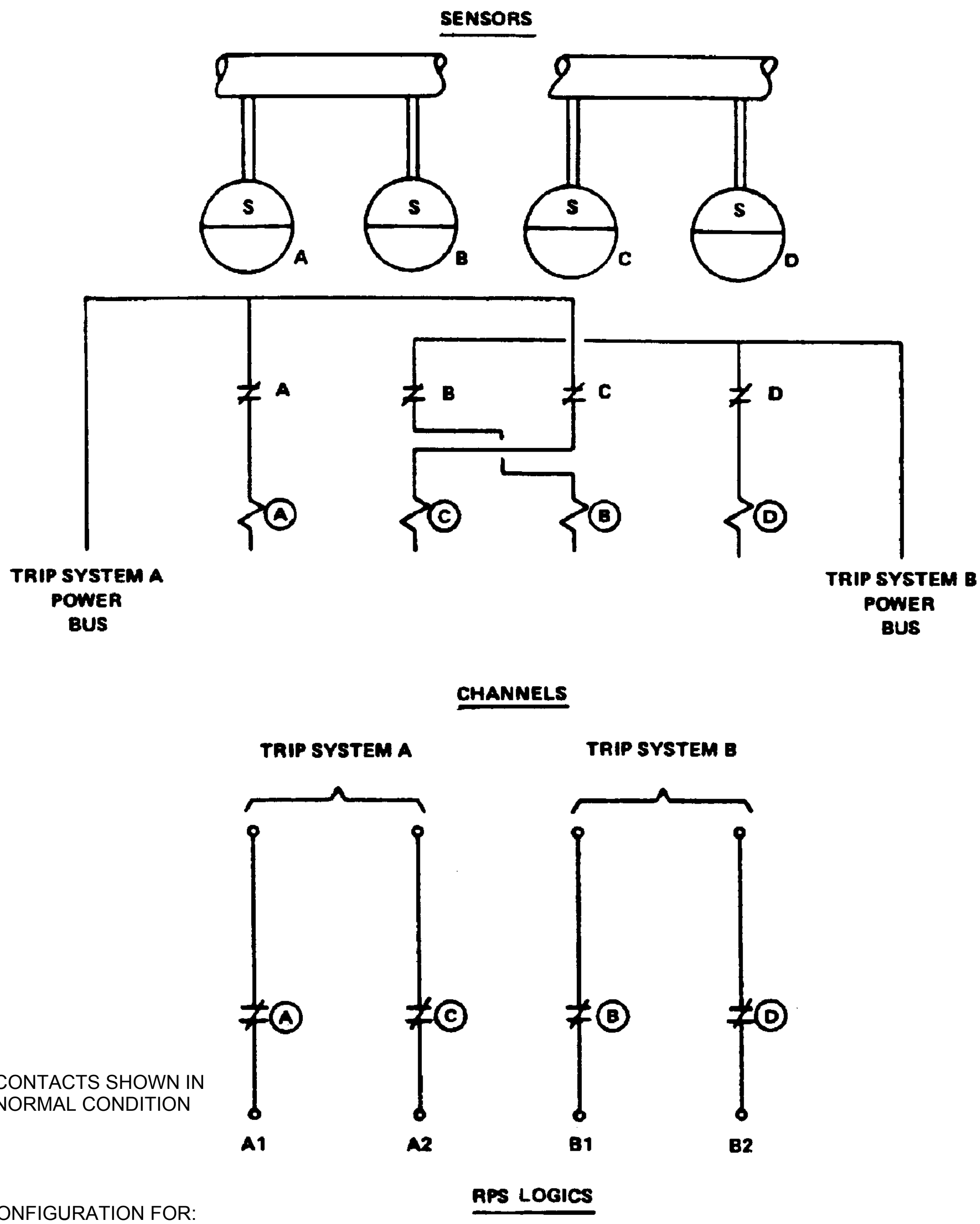
RELATIONSHIP BETWEEN NEUTRON MONITORING SYSTEM AND REACTOR PROTECTION SYSTEM

FIGURE 7.2-3



NOTE: CONTACTS SHOWN IN NORMAL CONDITION

TYPICAL CONFIGURATION FOR:
SCRAM DISCHARGE VOLUME HIGH WATER LEVEL
TURBINE CONTROL VALVE FAST CLOSURE

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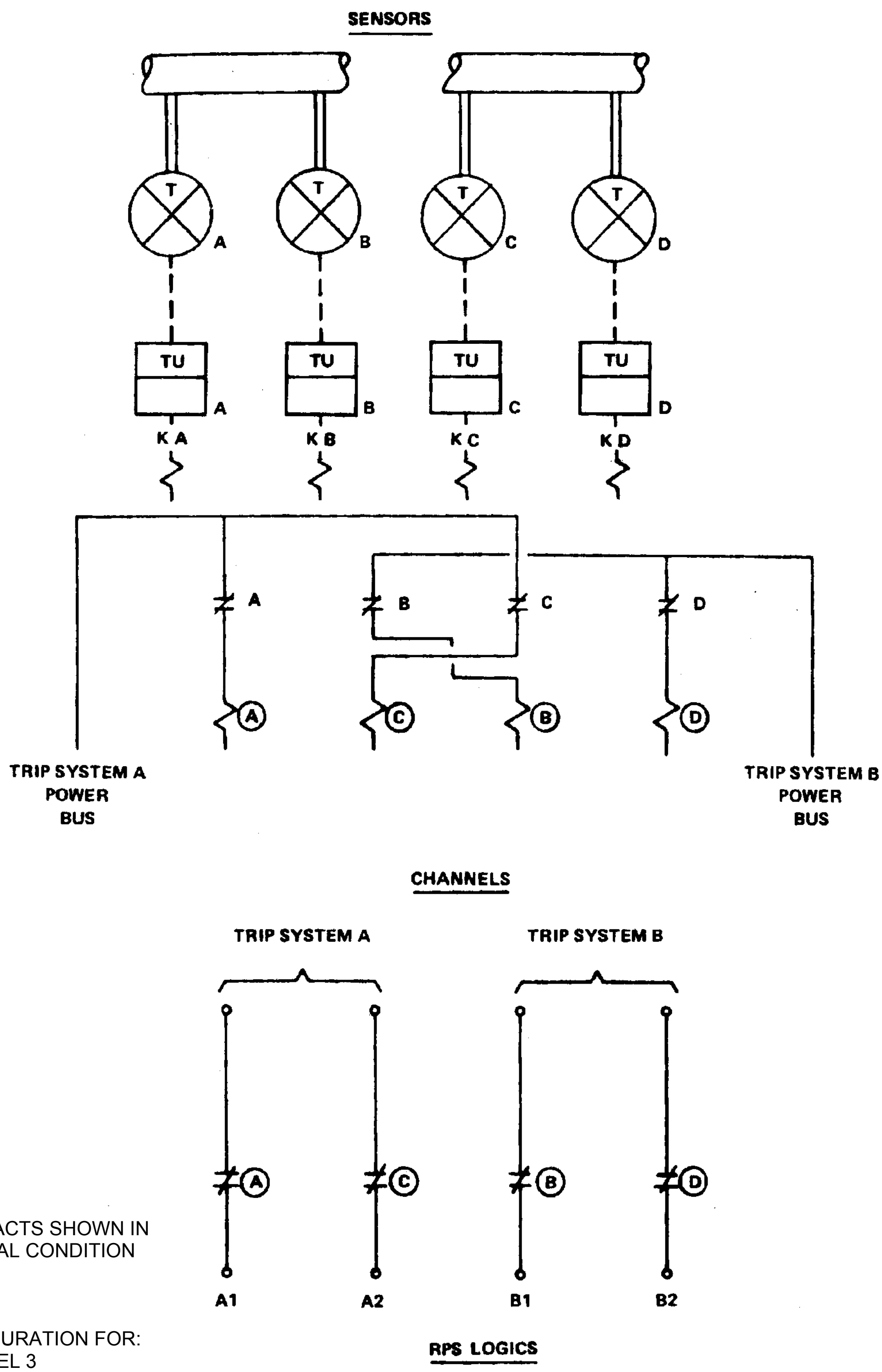
TYPICAL ARRANGEMENT OF CHANNELS AND LOGICS

FIGURE 7.2-4 (SHEET 1 OF 2)



NOTE: CONTACTS SHOWN IN NORMAL CONDITION

TYPICAL CONFIGURATION FOR:
RPV WATER LEVEL 3
REACTOR HIGH PRESSURE
PRIMARY CONTAINMENT HIGH PRESSURE

ACAD 107020402

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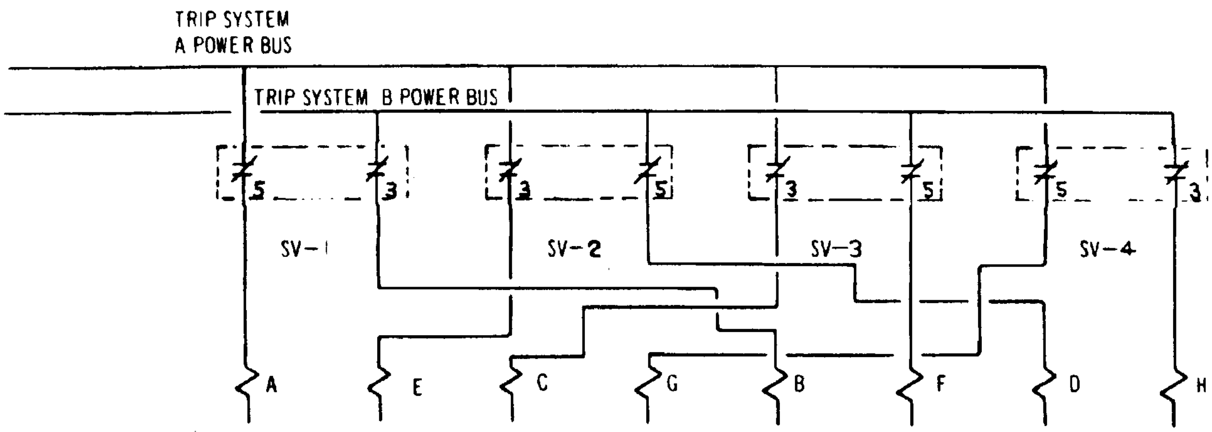
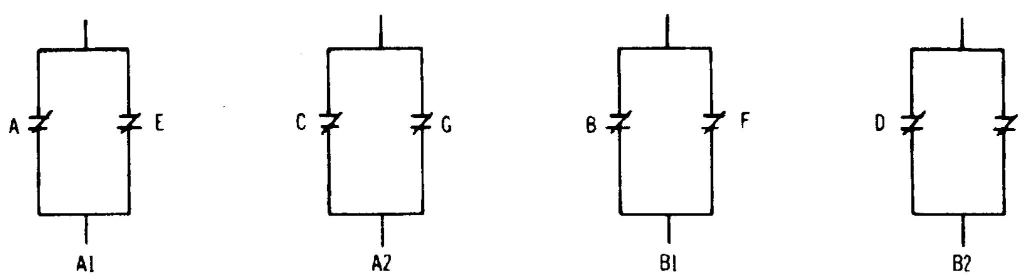
TYPICAL ARRANGEMENT OF CHANNELS AND LOGICS

FIGURE 7.2-4 (SHEET 2 OF 2)



TURBINE STOP VALVE CLOSURE CHANNELS



REACTOR PROTECTION SYSTEM LOGICS

NOTE CONTACTS SHOWN IN NORMAL CONDITION

SV = STOP VALVE

ACAD 1070205

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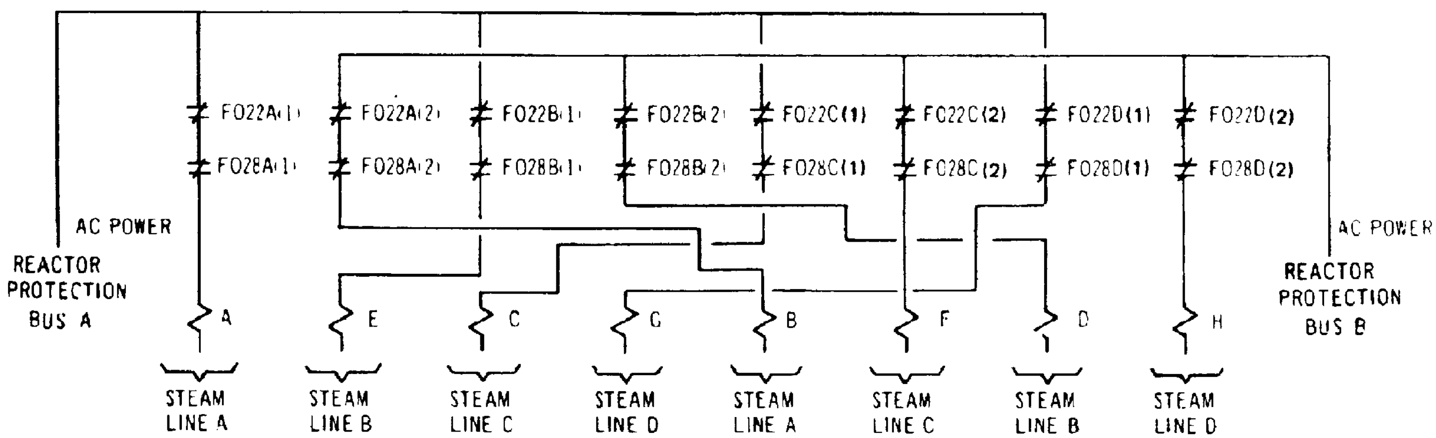
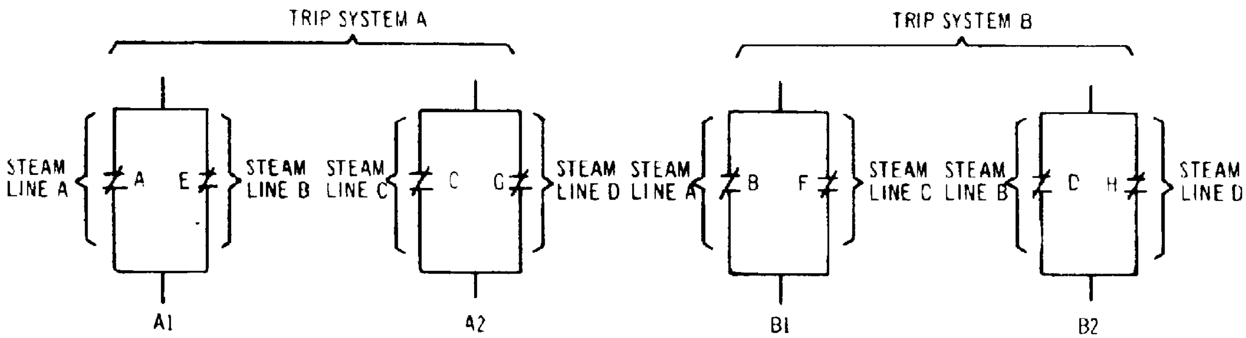
TYPICAL CONFIGURATION FOR
TURBINE STOP VALVE CLOSURE SCRAM

FIGURE 7.2-5



MAIN STEAM LINE ISOLATION CHANNELS
(SWITCH CONTACTS SHOWN IN POSITIONS WHEN ISOLATION VALVES LESS THAN 10% CLOSED)



REACTOR PROTECTION SYSTEM LOGICS
(CONTACTS SHOWN IN NORMAL CONDITIONS)

KEY:
F022A - STEAM LINE A. INBOARD VALVE
F028A - STEAM LINE A. OUTBOARD VALVE
F022B - STEAM LINE B. INBOARD VALVE
F028B - STEAM LINE B. OUTBOARD VALVE
F022C - STEAM LINE C. INBOARD VALVE
F028C - STEAM LINE C. OUTBOARD VALVE
F022D - STEAM LINE D. INBOARD VALVE
F028D - STEAM LINE D. OUTBOARD VALVE

ACAD 1070206

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TYPICAL CONFIGURATION FOR
MAIN STEAM LINE ISOLATION SCAM

FIGURE 7.2-6

7.3 PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM

7.3.1 SAFETY OBJECTIVE

To provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barriers, the primary containment and reactor vessel isolation control system initiates automatic isolation of appropriate lines which penetrate the primary containment whenever monitored variables exceed preselected operational limits.

A gross failure of the fuel barrier would allow the escape of fission products from the fuel. A gross failure of the nuclear system process barrier could allow the escape of gross amounts of reactor coolant. The loss of coolant could lead to overheating and failure of the fuel. For a gross failure of the fuel, the primary containment and reactor vessel isolation control system initiates isolation of the reactor vessel to contain released fission products. For a gross breach in the nuclear system process barrier outside the primary containment, the isolation control system acts to interpose additional barriers (isolation valve plugs) between the reactor and the breach, thus stopping the release of radioactive materials and conserving reactor coolant. For gross breaches in the nuclear system process barrier inside the primary containment, the primary containment and reactor vessel isolation control system acts to close off release routes through the primary containment barrier, thus trapping the radioactive material coming through the breach inside the primary containment.

7.3.2 DEFINITIONS

The primary containment isolation valves are grouped into three basic groups. Group A isolation valves are in lines that communicate directly with the reactor vessel and penetrate the primary containment.

Group B isolation valves are in lines that do not communicate directly with the reactor vessel, but penetrate the primary containment and communicate with the primary containment free space.

Group C isolation valves are in lines that penetrate the primary containment, but do not communicate directly with the reactor vessel, the primary containment free space, or the environs.

Additional discussion of this classification is contained in section 5.2.

7.3.3 SAFETY DESIGN BASES

A. To limit the uncontrolled release of radioactive materials to the environs, timely isolation of penetrations through the primary containment structure are initiated whenever the values of monitored variables exceed preselected operational limits.

B. To provide assurance that safety design basis A is fulfilled, the primary containment and reactor vessel isolation control system respond correctly to the sensed variables over the expected range of magnitudes and rates of change.

C. To provide assurance that important variables are monitored with precision, an adequate number of sensors are provided for monitoring essential variables that have spatial dependence.

D. To provide assurance that conditions indicative of a gross failure of the nuclear system process barrier are detected with sufficient timeliness and precision, primary containment and reactor vessel isolation control system inputs are derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

E. The time required for closure of the isolation valves is short, so that the release of radioactive material and the loss of coolant as a result of a breach of a line outside the primary containment are minimal.

F. The time required for closure of the main steam isolation valves (MSIVs) is not to be so short that inadvertent isolation of steam lines causes excessive fuel damage or excessive nuclear system pressure. This basis ensures that the MSIV closure speed is compatible with the ability of the reactor protection system (RPS) and pressure relief system to protect the fuel and nuclear system process barrier.

G. To provide assurance that closure of group A and group B automatic isolation valves is initiated, when required, with sufficient reliability, the following safety design bases are specified for the systems controlling group A and group B automatic isolation valves:

1. No single failure within the isolation control system prevents isolation action.

2. Any anticipated intentional bypass, maintenance, calibration, or test operation to verify operational availability does not impair the functional ability of the isolation control system to respond correctly to essential monitored variables.

3. The system is designed for a high probability that when any essential monitored variable exceeds the isolation setpoint, the event results in automatic isolation and does not impair the ability of the system to respond correctly as other monitored variables exceed their trip points.

4. Where a plant condition that requires isolation can be brought on by a failure or malfunction of a control or regulating system, and the same failure or

malfunction prevents action by one or more isolation control system channels designed to provide protection against the unsafe condition, the remaining portions of the isolation control system are required to meet the requirements of safety design bases A, B, C, and G1.

5. The power supplies for the primary containment and reactor vessel isolation control system are arranged so that loss of one supply cannot prevent automatic isolation when required.

6. The system is designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action requires deliberate operator action.

   MSIVs accomplish the seal-out completion of protective action by a circuit arrangement whereby each normally energized channel relay is isolated by its own series contact upon operation. These relays then remain deenergized until this series contact is bypassed by manual reset. All other reactor vessel isolation valves utilize the same arrangement to assure deenergization of the channel relay coil circuit once the relay contacts have opened. This design complies with Institute of Electrical and Electronics Engineers (IEEE) 279, paragraph 4.16.

   In order to reset the containment isolation valves following containment isolation, operation of two manual reset switches is required. These switches are located on adjacent panels, thereby precluding inadvertent resetting by a single operator movement or action.

7. There is sufficient electrical and physical separation between trip channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly.

8. Earthquake ground motions do not impair the ability of the primary containment and reactor vessel isolation control system to initiate automatic isolation.

H. The following safety design bases are specified to assure that the timely isolation of main steam lines is accomplished, when required, with extraordinary reliability:

   1. The motive force for achieving valve closure for one of the two tandem-mounted isolation valves in an individual steam line is derived from a different energy source than that for the other valve (compressed air and/or springs as a redundant method).

   2. At least one of the isolation valves in each of the steam lines does not rely on continuity of any variety of electrical power for the motive force to achieve closure.

I. To reduce the probability that the operational reliability and precision of the primary containment and reactor vessel isolation control system is degraded by operator error, the following safety design bases are specified for group A and group B automatic isolation valves:

1. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables is under the control of the plant operator or supervisory personnel.

2. The means for bypassing channels, logics, or system components is under the control of the plant operator. When the keylock test switches are selected to the test position the operator receives indication by means of a red warning light.

J. To provide the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier, it is possible for the control room operator to manually initiate isolation of the primary containment and reactor vessel.

K. The following bases are specified to provide the operator with the means to assess the condition of the primary containment and reactor vessel isolation control system and to identify conditions indicative of a gross failure of the nuclear system process barrier.

1. The primary containment and reactor vessel isolation control system is designed to provide the operator with information pertinent to the status of the system.

2. Means are provided for prompt identification of channel and trip system responses.

L. It is possible to check the operational availability of each essential channel, logic, and trip system.

7.3.4 DESCRIPTION

7.3.4.1 Identification

The primary containment and reactor vessel isolation control system includes the sensors, trip units, channels, switches, and remotely activated valve closing mechanisms associated with the valves, which when closed effect isolation of the primary containment, the reactor vessel, or both. It should be noted that the control systems for those group A and B isolation valves, which close by automatic action pursuant to the safety design bases, are the main subjects of this section. However, group C remotely operated isolation valves are included because they add to the operator's ability to effect manual isolation. Testable check valves are also included because they provide the operator with an ability to check that the check valve disc can respond to reverse flow. The primary containment and reactor vessel isolation control system is designed to meet the intent of IEEE Criteria for Nuclear Power Plants Protection Systems (IEEE 279) as the following tabulation shows:

In this tabulation the safety design bases are compared with the IEEE 279-1971 design requirements and explanatory notes are made where necessary. A detailed comparison of the reactor vessel and primary containment isolation control system with the IEEE criteria is made in General Electric (GE) Topical Report NEDO-10139 (June 1970).

IEEE 279-1971 Design Requirement	Safety Design Bases
4.1	A, B, E, F, G7, G8
4.2	G1, G2, G4
4.3	(Note 1)
4.4	(Note 1)
4.5	A, B, G7, G8
4.6	G2, G3, G7
4.7	G4
D.8	D
4.9	G2, I1, L
4.10	L (Note 2)
4.11	G2, I1, I2
4.12	G1, G2, I2
4.13	I2
4.14	I2

IEEE 279-1971 Design Requirement	Safety Design Bases
4.15	B, G3 (Note 3)
4.16	G6
4.17	J (Note 4)
4.18	I1
4.19	K2 (Note 5)
4.20	K1 (Note 5)
4.21	(Note 6)

NOTE: The same notes of paragraph 7.2.3.1 apply.

7.3.4.2 Power Supply

The power for the channels and logics of the isolation control system is supplied from the RPS motor-generator sets and the preferred power source. Isolation valves receive power from emergency buses. Power for the operation of two valves in a line is fed from different sources. In most cases one valve is powered from an ac bus of appropriate voltage, and the other valve is powered by dc from the plant batteries. The MSIVs, which are described in detail later, use ac, dc, and pneumatic pressure in the control scheme. ***Technical Requirements Manual (TRM) table T7.0-1 (incorporated by reference into the FSAR)*** lists the power supply for each isolation valve.

7.3.4.3 Physical Arrangement

TRM table T7.0-1 lists the lines that penetrate the primary containment and indicates the types and locations of the isolation valves installed in each line. Drawing nos. H-16062 and H-16063 identify some of these lines. Lines which penetrate the primary containment and are in direct communication with reactor vessel generally have two group A isolation valves, one inside the primary containment and one outside the primary containment. Lines which penetrate the primary containment and communicate with the primary containment free space but do not communicate directly with the reactor vessel, generally have two group B isolation valves located outside the primary containment. Group A and group B automatic isolation valves are considered essential for protection against the gross release of radioactive material in the event of a breach in the nuclear system process barrier. Process lines that penetrate the primary containment but do not communicate directly with the reactor vessel, the primary containment free space, or the environs, have at least one group C isolation valve located outside the primary containment which may close either by process action (reverse flow) or by remote manual operation. The controls for the automatic isolation valves are discussed in this part of the Final Safety Analysis Report. The valves, which are the subject of this text, are specifically identified in the detailed descriptions which follow.

Power cables are run in conduits and cable trays from appropriate electrical sources to the motor or solenoid involved in the operation of each isolation valve. The control arrangement for the MSIVs includes pneumatic piping and an air- or nitrogen-filled accumulator as an emergency source of motive power for closing.

Pressure transmitters and water level transmitters are mounted locally or on instrument racks. Cables are routed in conduits and cable trays from the transmitters to trip units (located in the main control room (MCR)) which provide low-water level and high-pressure trips. This instrumentation is part of the analog transmitter trip system (ATTS), which is discussed in section 7.18.

Valve position switches are mounted on the valve for which position is to be indicated. Switches are enclosed in cases to protect them from environmental conditions. Cables from each sensor are routed in conduits and cable trays to the MCR.

All signals transmitted to the control room are electrical; no pipe from the nuclear system or the primary containment penetrates the MCR. Pipes used to transmit level information from the reactor vessel to sensing instruments terminate inside the secondary containment (reactor building).

To ensure continued protection against the uncontrolled release of radioactive material during and after earthquake ground motions, the control systems required for the automatic closure of group A and group B valves are designed as Seismic Class 1 equipment, as described in appendix A.

7.3.4.4 Logic

Redundant automatic isolation valves in a given line are individually controlled by one of two isolation trip systems. Each trip system is maintained as an independent entity from the other trip system. If the number of operable channels cannot be met for one of the trip systems, the inoperable channel(s) or the associated trip system shall be tripped. Both trip systems are used to actuate closure of inboard and outboard MSIVs.

The MSIVs are controlled from four logic strings as shown in figure 7.3-1. The variables initiating automatic closure of the MSIVs are:

- Reactor pressure vessel (RPV) water level 1.
- High main steam line flow.
- High main steam line tunnel temperature.
- Low reactor pressure when in the RUN mode.

- Low condenser vacuum.

- High turbine building temperature.

Four channels are provided for each variable. One channel of each variable is connected to a particular logic to maintain channel independence and separation. One output of each logic actuator is used to control the inboard valves of all four main steam lines, and a second output of each logic actuator is used to control the outboard valves of all four main steam lines. The two individual outputs of each logic actuator are obtained from relay isolated contacts.

For each valve to automatically close, both of its solenoids must be deenergized. Each solenoid receives inputs from two logics, and either input can cause deenergization of that solenoid. Hence, automatic closure of any one valve is dependent upon one-out-of-two trips to one solenoid and one-out-of-two trips to the second solenoid.

The main steam line drain valves and reactor water sample valves are controlled from the four logic strings as shown in figure 7.3-2. In this instance, the logic actuator outputs are connected in a two-out-of-two logic to each isolation valve. The inboard valve isolates if both A1 and B1 logics are tripped; similarly, the outboard valve isolates if A2 and B2 logics are tripped.

Other inboard and outboard isolation valves are controlled from drywell high pressure and reactor water levels 2 and 3 variables. Two drywell pressure sensors are combined with two water level sensors to form a hybrid one-out-of-two-taken-twice network for the inboard isolation valves. Two other drywell high pressure and two other water level sensors are used in a second hybrid network for the outboard isolation valves. This logic is shown on drawing no. H-19901.

These same drywell pressure-water level logics are used with process radiation monitoring signals to produce other isolation actions including initiation of the standby gas treatment system (SGTS). In this instance, one process radiation monitor upscale signal is used with the inboard valves, and a second process radiation monitor upscale signal is used with the outboard valves. A downscale alarm is given in the event of an equipment malfunction which results in the loss of either monitoring signal.

The containment purge supply and the main exhaust isolation valves receive isolation signals upon any of the following conditions:

- Reactor water low level 3.

- High drywell pressure.

- Reactor building high radiation.

- Refueling floor high radiation.

- Primary containment high radiation.

In addition, these Class B isolation valves are capable of remote manual operation from the MCR. Each inboard and outboard isolation valve has its own isolation channel.

The reactor water cleanup (RWC) system isolation valves from the reactor are controlled by two logics using high differential flow, high area temperature, high area differential temperature, and RPV water level 2 isolation signals. One logic controls the inboard valve, and a second logic controls the outboard valve of the cleanup loop. Isolation signals based on the high differential flow are considered nonessential for achieving either a group B or C isolation. This isolation function is not an engineered safety feature. Standby liquid control system initiation isolates the outboard isolation valve.

The basic arrangement just described does not apply to group C isolation valves and testable check valves. Exceptions to the basic logic arrangement are made in several instances for certain group A and group B isolation valves as described in the following paragraph.

7.3.4.5 Operation

Automatic isolation valves that are normally closed receive the isolation signal as well as those valves that are open. The control system for each group A isolation valve is designed to provide closure of the valve in time to prevent uncovering the fuel as a result of a break in the line which the valve isolates. The control systems for group A and group B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline values of applicable regulations.

All automatic group A and group B valves and remotely operable group C valves can be closed by manipulating switches in the MCR, thus providing the operator with means independent of the automatic isolation functions.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the MCR to reopen a valve which has been automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions which initiated isolation have cleared.

A trip of an isolation control system channel is annunciated in the MCR so that the operator is immediately informed of the condition. The response of isolation valves is indicated by open-closed lights. All motor-operated group A and group B isolation valves have two sets of open-closed lights. One set is located near the manual control switches for the control of each valve from the control room. A second set is located in a separate central isolation valve position display in the control room. The positions of air-operated isolation valves are displaced in the same manner as motor-operated valves.

Inputs to annunciators, indicators, and the process computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output.

7.3.4.6 Isolation Valve Closing Devices and Circuits

TRM table T7.0-1 itemizes the type of closing device provided for each isolation valve intended for use in automatic or remote manual isolation of the primary containment or reactor vessel. To meet the requirement that automatic group A valves be fully closed in time to prevent the reactor vessel water level from falling below the top of the active fuel as a result of a break of the line which the valve isolates, the valve closing mechanisms are designed to give the minimum closing rates specified in ***TRM table T7.0-1*** or the Plant Hatch pump and valve inservice testing program. In many cases a standard closing rate of 12 in./min is adequate to meet isolation requirements. Using the standard rate, a 12-in. valve is closed in 60 s. Conversion to actual closing time can be made by using the size of the line to be isolated. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a standard closure rate, 12 in./min, is adequate for the automatic closing devices on group B isolation valves. The system design closure times for the various automatic isolation valves essential to reactor vessel isolation are as follows:

Valves	System Design Closure Times (s)	Line Nominal Size (in.)
MSIVs	3-5	24
Main steam line drain isolation valves	50	3
Reactor core isolation cooling (RCIC) system steam line isolation valves	30	3
High-pressure coolant injection (HPCI) system steam line isolation valves	67	10
Residual heat removal (RHR) system shutdown cooling supply isolation valves	46	20
RHR system shutdown cooling discharge isolation valves	63	24
RWC system supply isolation valves	40	6

Motor operators for group A and group B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve closing rates were considered in designing motor operators. Appropriate torque and limit switches are used to ensure proper valve seating. Handwheels, which are automatically disengaged from the motor operator when the motor is energized, are provided for local hand operation.

Direct solenoid-operated isolation valves and solenoid air pilot valves are chosen with electrical and mechanical characteristics which make them suitable for the service for which they are intended. Appropriate watertight or weathertight housings are used to ensure proper operation under accident conditions.

The pneumatic actuator used for testable check valves is designed to allow opening the valve at near 0-psi differential pressure across the valve. The actuator cannot close the valve against forward flow or prevent the closing of the valve against reverse flow. Thus, the check valve neither hinders forward fluid flow nor fails to stop reverse flow regardless of the condition of the actuator.

The MSIVs are spring/pneumatic-closing, pneumatic-opening, piston-operated valves designed to close upon loss of pneumatic pressure to the valve operator. This is fail-safe design. The control arrangement is shown on drawing nos. H-19902 and S-15247. Closure time for the valves is adjustable between 3 and 5 s. Each valve is piloted by two three-way packless, direct-acting, solenoid-operated pilot valves, one powered by ac, the other by dc. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve closing in the event of failure of the normal air supply system.

The valve pilot system and the pneumatic lines, as shown on drawing no. H-19902, are arranged so that when one or both solenoid-operated pilot valves are energized, normal air supply provides pneumatic pressure to the air-operated pilot valve to direct air pressure to the main valve pneumatic operator. This overcomes the closing force exerted by the spring to keep the main valve open. When both pilots are deenergized, as would be the result of both trip systems tripping or placing the manual switch in the closed position, the path through which air pressure acts is switched so that the opposite side of the valve operator is pressurized, thus assisting the spring in closing the valve. In the event of air supply failure the loss of air pressure causes the air-operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the air stored in the accumulator and by the spring.

Air pressure acting alone, and the force exerted by the spring acting alone, are each capable of independently closing the valve. The isolation valves inside the primary containment (inboard) are designed to close under either pneumatic pressure or spring force, with the vented side of the piston operator at the containment peak accident pressure. (The outboard valve is exactly the same design, although it is subjected only to atmospheric pressures.) The accumulator volume was chosen to provide enough pressure to close the valve when the pneumatic supply to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closing.

A separate, single, solenoid-operated pilot valve with an independent test switch is included to allow manual testing of each isolation valve from the MCR. The testing arrangement is designed to give a slow closure of the isolation valve being tested to avoid rapid changes in steam flow and nuclear system pressure. Slow closure of a valve during testing requires 50 to 60 s. The valve mechanical design is discussed further in section 4.6, Main Steam Line Isolation Valves.

7.3.4.7 Isolation Functions and Settings

The isolation trip settings of the primary containment and reactor vessel isolation control system are listed in table 7.3-2. The functions that initiate automatic isolation are itemized in ***TRM table T7.0-1*** in terms of the lines that penetrate the primary containment. This latter table includes all lines of concern for isolation purposes. Although this section is concerned with the electrical control systems that initiate isolation to prevent direct release of radioactive material from the primary containment or nuclear system process barrier, the additional information given in ***TRM table T7.0-1*** can be used to assess the overall (electrical and mechanical) isolation effectiveness of each system having lines which penetrate the primary containment.

In general, the high-flow settings are intended to produce rapid isolation for severe rupture of steam and process lines while the temperature setpoints are intended to detect small leaks in the various lines. The high-flow settings are to preclude spurious operation while limiting any resulting site boundary doses to a value less than that of the main steam line break accident discussed in HNP-2-FSAR chapter 15, Safety Analysis. The temperature settings which relate to ambient conditions for the various equipment rooms (reactor cleanup, HPCI, RCIC, and main steam lines) are chosen to isolate the systems for identified leakage below 25 gal/min. The only temperature differential isolation is sensed in the suppression chamber and the reactor water cleanup rooms.

The temperature sensors in the equipment rooms are located and shielded such that they are responsive to air temperature only and are not affected by direct radiation or impingement. Differential temperatures are measured by placing temperature sensors near both the inlet and outlet ventilation paths for the particular room.

Temperature sensors are located near the outlet of the emergency area coolers in the HPCI and RCIC rooms in order to detect high room temperature resulting from steam leakage from the RCIC and HPCI steam lines in these rooms. Because there are no steam lines other than the HPCI steam lines in the HPCI room, and no steam lines other than the RCIC steam lines in the RCIC room, spurious isolation of HPCI or RCIC cannot result from failures of other system lines in these rooms. A 4 x 4 array of temperature sensors are located above the main steam lines in the steam tunnel. These sensors isolate the main steam lines only. To eliminate inadvertent isolation of the main steam lines due to a sensor being impinged upon by a small steam leak in a main steam line or RCIC steam line which also passes through the steam tunnel, the control logic is such that two sensors in a one-out-of-two-taken-twice logic must sense high temperature in order to cause main steam line isolation. Final ambient temperature settings for the sensors located in equipment areas are given in table 7.3-2. Isolation function and trip settings used for the electrical control of isolation valves in fulfillment of the previously stated safety design bases are discussed in the following paragraphs.

Reactor Vessel Low Water Level

Refer to the isolation group signals in ***TRM table T7.0-1***. Low water level in the reactor vessel could indicate that either reactor coolant is being lost through a breach in the nuclear system process barrier or that the normal supply of reactor feedwater has been lost and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. RPV low water level initiates closure of various group A valves and group B valves. The closure of group A valves is intended to either isolate a breach in any of the lines in which valves are closed or conserve reactor coolant by closing off process lines. The closure of group B valves is intended to prevent the escape of radioactive materials from the primary containment through process lines which are in communication with the primary containment free space.

Three RPV low water level isolation trip settings are used to complete the isolation of the primary containment and the reactor vessel. The highest RPV low water level isolation trip setting (RPV water level 3), initiates closure of all group A and group B valves in major process lines except the main steam lines, the RWC lines, the main steam line drain valves, and the reactor water sample lines. The main steam lines are left open to allow the removal of heat from the reactor core. The RWC lines are isolated at RPV water level 2. The lowest RPV water level isolation setting (level 1) completes the isolation of the primary containment and reactor vessel by initiating closure of the MSIVs and any other group A or group B valves that must be shut to isolate minor process lines.

The first low water level setting (level 3), which is coincidentally the same as the RPV low water level scram setting, was selected to initiate isolation at the earliest indication of a possible breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious isolation. Isolation of the following lines is initiated when RPV low water level falls to this first setting (level 3). (See isolation group signals in ***TRM table T7.0-1***):

- RHR reactor shutdown cooling supply.[a]
- Drywell to torus differential pressure system isolation valves.[b]
- Drywell equipment drain discharge.
- Drywell floor drain discharge.
- Drywell purge inlet.[a]
- Drywell main exhaust.[a]
- Suppression chamber exhaust valve bypass.[a]
- Suppression chamber purge inlet.[a]
- Suppression chamber main exhaust.[a]
- Drywell exhaust valve bypass.[a]
- Drywell and suppression chamber nitrogen supply line.[a]

a. Closed during normal power operation.
b. Closed during normal power operation; system no longer functional.

- Drywell and suppression chamber nitrogen makeup line (one valve open, one valve closed).
- H_2/O_2 analyzer and fission products monitoring system.
- Traversing incore probe (TIP) tubes.
- Drywell pneumatic system from drywell.
- Post-accident sampling system.

The second, low RPV water level isolation setting (RPV water level 2) was selected low enough to avoid isolation of the RWC lines due to a level transient caused by void collapse following a scram from normal power levels, yet high enough to complete isolation in time for the operation of the HPCI and RCIC systems in the event of a break.

The lowest RPV low water level isolation setting (RPV water level 1) was selected low enough to allow the removal of heat from the reactor for a predetermined time following the scram and high enough to complete isolation in time for the operation of the emergency core cooling subsystems to perform their safety function in the event of a break in the nuclear system process barrier. Delaying MSIV closure until RPV water level decreases to level 1 reduces the challenges to the safety relief valves (SRVs) and loads on the torus due to subsequent SRV actuations. A delayed MSIV isolation allows more steam to be released from the reactor through the main steam lines prior to an SRV actuation. The subsequent pressurization rate following MSIV isolation is also reduced because of the lower decay heat rate at this later time. This level setting is low enough that partial losses of feedwater supply would not unnecessarily initiate full isolation of the reactor, thereby disrupting normal plant shutdown or recovery procedures. Isolation of the following lines is initiated when the reactor vessel water level falls to RPV water level 1 (See the isolation group signals in ***TRM table T7.0-1***):

- All four main steam lines.
- Main steam line drain.[a]
- Reactor water sample line.

<u>Main Steam Line High Radiation</u>

Refer to the isolation group signals in ***TRM table T7.0-1***. High radiation in the vicinity of the main steam lines could indicate a gross release of fission products from the fuel. High radiation near the main steam lines initiates isolation of the reactor water sample line.

a. Closed during normal power operation.

The high-radiation trip setting is selected high enough above background radiation levels to avoid spurious isolation, yet low enough to promptly detect a gross release of fission products from the fuel. Further information regarding the high-radiation setpoint is available in section 7.12, Process Radiation Monitoring.

Main Steam Line High Flow

Refer to the isolation group signals in ***TRM table T7.0-1***. Main steam line high flow could indicate a break in a main steam line. The automatic closure of various group A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of the main steam line high flow, the following lines are isolated:

- All four main steam lines.
- Main steam line drain.[a]
- Reactor water sample line.

The main steam line high-flow trip setting was selected high enough to permit the isolation of one main steam line for test at rated power without causing an automatic isolation of the rest of the steam lines yet low enough to permit early detection of a gross steam line break.

Main Steam Line Space High Temperature

Refer to the isolation group signals in ***TRM table T7.0-1***. High temperature in the space in which the main steam lines are located outside of the primary containment could indicate a breach in a main steam line. The automatic closure of various group A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperatures occur in the main steam line space, the following pipelines are isolated:

- All four main steam lines.
- Main steam drain line.[a]
- Reactor water sample line.

The main steam line space high-temperature trip is set far enough above the temperature expected during operations at rated power to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

a. Closed during normal power operation.

Low Steam Pressure at Turbine Inlet

Refer to the isolation group signals in ***TRM table T7.0-1***. Low steam pressure upstream of the turbine stop valves while the reactor is operating could indicate a malfunction of the pressure regulator in which the turbine control valves or turbine bypass valves open fully. This action could cause rapid depressurization of the nuclear system. From part-load operating conditions, the rate of decrease of nuclear system saturation temperature could exceed the design rate of change of vessel temperature. A rapid depressurization of the reactor vessel while the reactor is near full power could result in undesirable differential pressures across the channels around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without adequate preventative action, could require thorough vessel analysis or core inspection prior to returning the reactor to power operation. To avoid the time consuming requirements following a rapid depressurization, the steam pressure at the turbine inlet is monitored and upon falling below a preselected value with the reactor in the RUN mode initiates isolation of the following lines:

- All four main steam lines.
- Main steam drain line.[a]
- Reactor water sample line.

The low steam pressure isolation setting was selected far enough below normal turbine inlet pressures to avoid spurious isolation yet high enough to provide timely detection of a pressure regulator malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, this discussion is included here to complete the list of isolation functions.

Primary Containment (Drywell) High Pressure

Refer to the isolation group signals in ***TRM table T7.0-1***. High pressure in the drywell could indicate a breach of the nuclear system process barrier inside the drywell. The automatic closure of various containment isolation valves prevents the release of significant amounts of radioactive material from the primary containment. Automatic closure of selected reactor vessel isolation valves prevents possible addition to the overpressure. Upon detection of a high drywell pressure, the following lines are isolated:

- Drywell equipment drain discharge.
- Drywell floor drain discharge.
- TIP tubes (group A).
- Drywell purge inlet.[a]

a. Closed during normal power operation.

- Drywell main exhaust.[a]
- Suppression chamber exhaust valve bypass.[a]
- HPCI/RCIC turbine exhaust vacuum breaker.[b]
- Suppression chamber purge inlet.[a]
- Suppression chamber main exhaust.[a]
- Drywell exhaust valve bypass.[a]
- H_2/O_2 analyzer and fission product monitoring systems sample lines.
- Drywell and suppression chamber nitrogen supply line.[a]
- Drywell and suppression chamber nitrogen makeup line (one valve open, one valve closed).
- Drywell pneumatic system from drywell.
- TIP guide tubes.
- Post-accident sampling system.

The primary containment high-pressure isolation setting was selected to be as low as possible without inducing spurious isolation trips.

<u>RCIC Equipment Room High Ambient Temperature and Suppression Pool Area High Ambient and High Differential Temperature</u>

Refer to the isolation group signals in ***TRM table T7.0-1***. High ambient temperature in the RCIC equipment room or high ambient or differential temperature in the suppression pool area could indicate a break in the RCIC steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high ambient temperature is sensed in the suppression pool area or high differential temperature is sensed between the inlet and outlet ducts which ventilate the suppression pool area, a timer is initiated in the control room. If the high temperature or high differential temperature is not reduced below the trip point before the timer runs out, the RCIC steam line is isolated. When high ambient temperature is sensed at the RCIC equipment compartment cooler, the RCIC steam line is isolated. The high temperature isolation setting was selected far enough above anticipated normal operational

a. Closed during normal power operation.
b. In conjunction with HPCI/RCIC low steam line pressure, respectively.

levels to avoid spurious operation but low enough to provide timely detection of a RCIC turbine steam line break. The timer setting is established to eliminate spurious isolations which might occur when switching from normal ventilation to standby ventilation. Instrumentation actuates alarms in the MCR on high differential and high ambient temperature.

RCIC Turbine High Steam Flow

Refer to the isolation group signals in ***TRM table T7.0-1***. RCIC turbine high steam flow could indicate a large break in the RCIC turbine steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. The RCIC turbine high steam flow trip setting was selected high enough to avoid spurious isolation, i.e., above the high steam flowrate encountered during turbine starts. The setting was selected low enough to provide timely detection of a RCIC turbine steam line break.

RCIC Turbine Steam Line Low Pressure

Refer to the isolation group signals in ***TRM table T7.0-1***. Low pressure in the RCIC steam line could indicate a break in the RCIC steam line. Therefore, the RCIC steam line isolation valves are automatically closed. The steam line low-pressure function is provided so that in the event a gross rupture of the RCIC steam line occurred upstream from the high-flow sensing location, thus negating the high-flow indication function, isolation would be effected on low pressure. The isolation setpoint is chosen at a pressure below that which the RCIC turbine can effectively operate.

RCIC Turbine Exhaust Diaphragm High Pressure

Refer to the isolation group signals in ***TRM table T7.0-1***. High pressure in the RCIC turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The RCIC exhaust line is protected from overpressure by the rupture disk. In the event of a disk rupture, the steam line isolation valves are automatically closed to isolate the RCIC steam supply, thereby preventing the venting of reactor steam to the torus airspace. The turbine exhaust pressure trip setting is selected high enough to avoid isolation of the RCIC if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

HPCI Equipment Room High Ambient Temperature and Suppression Pool Area High Ambient and High Differential Temperature

Refer to the isolation group signals in ***TRM table T7.0-1***. High ambient temperature in the HPCI equipment room or high ambient or differential temperature in the suppression pool area could indicate a break in the HPCI system turbine steam line. The automatic closure of the HPCI steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high ambient or differential temperature is sensed in the suppression pool area ducts which ventilate the suppression pool area a timer is initiated. If the high temperature or high differential temperature is not reduced below the trip point before the timer runs out, the HPCI steam line is isolated. When high ambient temperature is sensed at the compartment cooler, the HPCI steam line is isolated. The high-temperature isolation setting was selected far enough above anticipated normal HPCI system operational levels to avoid spurious isolation, but low enough to provide timely detection of a HPCI turbine steam line break. The timer setting is established to eliminate spurious isolations which might occur when switching from normal ventilation to standby ventilation. Nonsafety-related instrumentation actuates alarms in the MCR on high ambient and high differential temperature and high ambient temperature in the compartment cooler.

HPCI Turbine High Steam Flow

Refer to the isolation group signals in ***TRM table T7.0-1***. HPCI turbine high steam flow could indicate a break in the HPCI turbine steam line. The automatic closure of the HPCI steam line isolation valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of HPCI turbine high steam flow the HPCI turbine steam line is isolated. The high steam flow trip setting was selected high enough to avoid spurious isolation, i.e., above the high steam flowrate encountered during turbine starts. The setting was selected low enough to provide timely detection of a HPCI turbine steam line break.

HPCI Turbine Steam Line Low Pressure

Refer to the isolation group signals in ***TRM table T7.0-1***. Low pressure in the HPCI steam line could indicate a break in the HPCI steam line. Therefore, the HPCI steam line isolation valves are automatically closed. The steam line low-pressure function is provided so that in the event a gross rupture of the HPCI steam line occurred upstream from the high-flow sensing location, thus negating the high-flow indicating function, isolation would be effected on low pressure. The isolation setpoint is chosen at a pressure below that at which the HPCI turbine can effectively operate.

HPCI Turbine Exhaust Diaphragm High Pressure

Refer to the isolation group signals in ***TRM table T7.0-1***. High pressure in the HPCI turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The HPCI exhaust line is protected from overpressure by the rupture disk. In the event of a disk rupture, the steam line isolation valves are automatically closed to isolate the HPCI steam supply, thereby preventing the venting of reactor steam to the torus airspace. The turbine exhaust pressure trip setting is selected high enough to avoid isolation of the HPCI if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

Reactor Building or Refueling Floor Ventilation Exhaust High Radiation

Refer to the isolation group signals in ***TRM table T7.0-1***. High radiation in the reactor building or refueling floor ventilation exhaust could indicate a breach of the nuclear system process barrier inside the primary containment which would result in increased airborne radioactivity levels in the primary containment exhaust to the secondary containment. The automatic closure of certain group B valves acts to close off release routes for radioactive material from the primary containment into the secondary containment (reactor building). Reactor building or refueling floor ventilation exhaust high radiation initiates isolation of the following lines:

- Drywell purge inlet.[a]
- Drywell main exhaust.[a]
- Suppression chamber exhaust valve bypass.[a]
- Suppression chamber purge inlet.[a]
- Suppression chamber main exhaust.[a]
- Drywell exhaust valve bypass.[a]
- Drywell and suppression chamber nitrogen supply line.[a]
- Drywell and suppression chamber nitrogen makeup line (one valve open, one valve closed).
- H_2/O_2 analyzer and fission product monitoring systems sample lines.
- Drywell pneumatic system from drywell.
- Post-accident sampling system.

The high-radiation trip setting selected is far enough above background radiation levels to avoid spurious isolation, but low enough to provide timely detection of nuclear system process barrier leaks inside the primary containment. Because the primary containment high-pressure isolation function and the RPV low water level isolation function are adequate in effecting appropriate isolation of the above lines for gross breaks, the reactor building or refueling floor ventilation exhaust high-radiation isolation function is provided as a third redundant method of detecting breaks in the nuclear system process barrier significant enough to require automatic isolation.

a. Closed during normal power operation.

Primary Containment High Radiation

Refer to the isolation group signals in ***TRM table T7.0-1***. Auto isolation logic upon high-radiation detection inside primary containment provides a means to protect against substantial releases of radiation to the environs due to an accident by closing the purge supply and the main exhaust valves. This containment isolation logic satisfies the requirements of NUREG-0737, Item II.E.4.2(7), Containment Isolation Dependability, Isolation of Purge and Vent Valves on High Radiation.

Cleanup System Equipment Room High Ambient and High Differential Temperature

Refer to the isolation group signals in ***TRM table T7.0-1***. High ambient or differential temperature in the cleanup system equipment room could indicate a break in the cleanup system line carrying high temperature water. When high differential temperature is sensed between the inlet and outlet ducts which ventilate the cleanup system room or high temperature in the room is sensed, the cleanup system is automatically isolated. The high ambient and differential temperature trip settings are selected high enough to avoid spurious isolation, yet low enough to provide timely detection and isolation of a break in the cleanup system. Nonsafety-related instrumentation actuates alarms in the MCR on high differential or high ambient temperature.

Cleanup System High Differential Flow

Refer to the isolation group signals in ***TRM table T7.0-1***. High differential flow in the cleanup system measured between a point immediately outside the primary containment on the discharge side of the pump and points downstream from the filter-demineralizers could indicate a break between these points. The automatic closure of the cleanup system isolation valves prevents excessive loss of reactor coolant and significant amounts of radioactive material. A break downstream from the filter-demineralizers would be less consequential because of the low radioactivity of the water at this point. The high differential flow trip setting was selected high enough to avoid spurious isolations yet low enough to provide timely detection and isolation.

Isolation signals, based upon the high differential flow, are considered nonessential for achieving either a group B or C isolation. This isolation function is not an engineered safety feature.

Turbine Condenser Low Vacuum

Refer to the isolation group signals in ***TRM table T7.0-1***. Main turbine condenser low vacuum would indicate a leak in the condenser. Initiation of the automatic closure of various Class A valves prevents excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of turbine condenser low vacuum, the following lines are isolated:

- All four main steam lines.
- Main steam line drain.[a]
- Reactor water sample line.

The turbine condenser low-vacuum trip setting is selected far enough below the normal operating vacuum (higher pressure) to avoid spurious isolation, yet high enough to provide an isolation signal prior to the rupture of the condenser and subsequent loss of reactor coolant and release of radioactive material.

The only engineered safety features not in a Class 1 structure are the electrical channels to the turbine condenser used to isolate the main steam lines on loss of condenser vacuum. These channels are routed from a cabinet in the control building to the pressure switches in the condenser in rigid steel conduit. Full separation is provided and no other circuits are run through these conduits. These conduits are run under the turbine building shield at el 164 ft to provide physical separation until the vertical run to the condenser at el 112 ft.

This function would be active in all modes and set at a vacuum of ~ 7.0-in. Hg (22.23-in. Hg absolute pressure). Manual bypassing of the low-vacuum trips is permitted. Four channels of instrumentation (pressure switches, interface relays, etc.) are required to obtain four independent contacts, opening on low condenser vacuum for the MSIV isolation control logic.

The manual bypass, which is annunciated, is provided to facilitate the following operations: The bypass allows cold shutdown testing of the main steam line isolation logic and allows stroking the MSIVs open and closed for maintenance even though there is no condenser vacuum.

The bypass allows the MSIVs to be opened so seal steam, and an ejector steam can be available at the turbine and condenser, thereby allowing restart of the reactor from a hot pressurized condition. Attempting to establish condenser vacuum without seal steam from the hot condition by the mechanical vacuum pump may damage the turbine shaft seals. The sensors and other equipment which provide the subject MSIV closure function are designed to meet the requirements of IEEE 279. While located in a structure not specifically designed to seismic requirements, the circuits are routed in conduit so as to provide separation between channels and protection from turbine associated trips, i.e., main turbine stop valve closure and control valve fast closure.

Drywell Pneumatic System High Flow

Refer to the isolation group signals in ***TRM table T7.0-1***. High flow in the drywell pneumatic supply lines, measured at a point immediately before the primary containment penetrations, could indicate a break inside the containment. Continuous high flow for greater than 10 min will cause automatic closure of the respective isolation valves, preventing the potential overpressurization of the containment and, thereby, maintaining primary containment integrity.

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a. Closed during normal power operation.

7.3.4.8 Instrumentation

Sensors providing inputs to the primary containment and reactor vessel isolation control system are not used for the automatic control of process systems, thus separating the functional control of protection systems and process systems. Channels are physically and electrically separated to assure that a single physical event cannot prevent isolation. Channels for one monitored variable that are grouped near to each other provide inputs to different isolation trip systems.

RPV water levels 1, 2, and 3 signals are initiated from eight differential pressure transmitters which sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual water level in the vessel. Cables are routed from the transmitters to trip units (located in the MCR) which trip on a low RPV water level. Four of these trip units have contacts which are used to indicate that water level has decreased to RPV low water level 3 isolation settings; the other four trip units and associated four slave trip units have contacts which are used to indicate that water level has decreased to RPV water levels 2 and 1 isolation settings. The transmitter/trip units and their contacts for each level setting are arranged in pairs; each contact in a pair provides a signal to a different trip system. Two lines, attached to taps above and below the water level on the reactor vessel, are required for the differential pressure measurement for each pair of transmitters. The two pair of lines terminate outside the primary containment and inside the reactor building; they are physically separated from each other and tap off the reactor vessel at widely separated points. The RPV low water level transmitters sense level from these pipes. This arrangement assures that no single physical event can prevent isolation (drawing no. H-16063). This level instrumentation is part of the ATTS, which is discussed in section 7.18.

Main steam line radiation is monitored by four radiation monitors, which are described in section 7.12.

High flow in each main steam line is sensed by four differential pressure transmitters which sense the pressure difference across the flow restrictor in that line. Cables are routed from the transmitters to trip units located in the MCR. Drawing no. H-16062, illustrates the general arrangement of instruments used to sense the flow in a single main steam line. Figure 7.3-4 illustrates how the 16 differential pressure transmitters/trip units are combined to form four channels. Each main steamline isolation logic receives an input signal from each main steam line high-flow channel (drawing no. H-16062). The A, B, C, or D dP transmitters for the four main steam lines are on different racks located adjacent to each other, and the C and D dP transmitters are on another pair of adjacent racks for the four main steam lines. Either A, B, C, or D trip from any steam line causes isolation of MSL drain line and reactor sample lines. Either (A or C) and (B or D) causes MSIV isolation. This design meets the single-failure criterion. This differential pressure instrumentation is part of the ATTS, which is discussed in section 7.18.

High temperature in the vicinity of the main steam lines is detected by 16 RTDs located along the main steam lines between the drywell wall and the turbine building wall and by 64 temperature switches located in the turbine building. Cables are routed from these RTDs to trip units located in the MCR. The detectors are located so that they sense any increase in temperature above ambient temperature. An additional temperature sensor is located near the 16 detectors for remote temperature readout and alarm at high temperature. The main steam line space temperature detection system is designed to detect leaks of from 1% to 10% of rated steam flow. A total of four main steam line space high-temperature channels are provided. Each main steam line isolation logic receives an input signal from one main steam line space high-temperature channel.

Main steam line low pressure is sensed by four bourdon tube-operated pressure switches which sense pressure downstream of the outboard MSIVs. The sensing point is located at the header that connects the four steam lines upstream to the turbine stop valves. Each switch is part of an independent channel. Each channel provides a signal to one isolation logic.

Primary containment pressure is monitored by four pressure transmitters which are mounted locally outside the drywell. Pipes that terminate in the reactor building connect the transmitters with the drywell interior. Cables are routed from the transmitters to trip units located in the MCR. The transmitters/trip units are grouped in pairs, physically separated and electrically connected to the isolation control system so that no single event prevents isolation due to primary containment pressure. This instrumentation is part of the ATTS, which is discussed in section 7.18.

High RCIC equipment room ambient temperature is sensed at the standby cooler by two RTDs. Cables are routed from these RTDs to trip units located in the MCR. Each trip unit is arranged as one channel. A trip of either channel isolates the RCIC steam line. Nonsafety-related temperature switches actuate alarms in the MCR on high RCIC equipment room ambient temperature. Figure 7.3-5 illustrates the arrangement. All RCIC isolation functions and their arrangements are shown in detail on drawing nos. H-16334, H-16335, and H-19955 through H-19962. This instrumentation is part of the ATTS, which is discussed in section 7.18.

High flow in the RCIC turbine steam line is sensed by two differential pressure transmitters, each of which monitors the differential pressure across an elbow installed in the RCIC turbine steam supply line. The trip units trip on high differential pressure (high flow) or low differential pressure (indicative of an instrument line break). Cables are routed from these transmitters to trip units located in the MCR. The arrangement is illustrated in figure 7.3-6. The tripping of either trip unit initiates isolation of the RCIC turbine steam line. This instrumentation is part of ATTS, which is discussed in section 7.18.

Low pressure in the RCIC turbine steam line is sensed by four pressure transmitters from the RCIC turbine steam line upstream of the isolation valves. Cables are routed from these transmitters to trip units located in the MCR. The transmitters/trip units are arranged as two trip systems either of which can trip to initiate isolation of the RCIC turbine steam line. Each trip system receives inputs from two trip units, both of which must trip the trip system. Figure 7.3-6 illustrates this arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.18.

High pressure in the RCIC turbine exhaust results in fracture of the rupture disk in the vent line which is connected to the turbine exhaust. High pressure downstream from the rupture disk is sensed by four pressure transmitters. Cables are routed from these transmitters to trip units located in the MCR. Each set is arranged as two trip systems. Each trip system receives input signals from two trip channels. Both trip channels must trip to initiate isolation. Figure 7.3-6 illustrates the arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.18.

HPCI pipe penetration room high temperature is sensed by two RTDs that are appropriately located to detect a very small leak in the HPCI system steam piping and are capable of detecting leaks equivalent to 25 gal/min. Cables are routed from these RTDs to trip units located in the MCR. Each RTD/trip unit is arranged as one channel. A trip of either channel isolates the HPCI steam line. Two additional thermocouples, which are routed to temperature switches, are located near the RTDs that initiate an alarm in the MCR. All HPCI isolation functions and their arrangements are shown in detail on figure 7.4-2 and drawing nos. H-19947 through H-19954. The RTDs and trip units are part of the ATTS, which is discussed in section 7.18.

High flow in the HPCI turbine steam line is sensed by two differential pressure transmitters, each of which monitors the differential pressure across an elbow installed in the HPCI turbine steam line. Cables are routed from the transmitters to trip units located in the MCR. The trip units trip on high differential pressure (high flow) or low differential pressure (indicative of an instrument line break). The arrangement is illustrated in figure 7.3-6. The tripping of either trip unit initiates isolation of the HPCI turbine steam line.

Low pressure in the HPCI turbine steam line is sensed by four pressure transmitters from the HPCI turbine steam line upstream of the isolation valves. Cables are routed from the transmitters to trip units located in the MCR. The trip units are arranged as two trip systems, either of which can trip to initiate isolation of the HPCI turbine steam line. Each trip system receives inputs from two pressure trip units, both of which must trip to initiate isolation. Figure 7.3-6 illustrates this arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.18.

High pressure in the HPCI turbine exhaust results in fracture of the rupture disk in the vent line which is connected to the turbine exhaust. High pressure downstream from the rupture disk is sensed by four pressure transmitters. Cables are routed from these transmitters to trip units located in the MCR. The transmitters/trip units are arranged as two trip systems. Each trip system receives input signals from two trip units. Both trip units must trip to initiate isolation. Figure 7.3-6 illustrates this arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.18.

Reactor building ventilation exhaust radiation is monitored by two sets of reactor building ventilation exhaust monitors, which are described in subsection 7.12.5. Each monitoring trip channel provides one input to each applicable isolation trip system. The channels are arranged so that any one of the channels can initiate isolation.

Primary containment atmosphere radiation is monitored by redundant radiation monitors. Each monitoring trip channel provides one input to each applicable isolation trip logic. The channel "A" trip logic sends an isolation signal to close the inboard isolation valves in the containment main supply/purge lines. The channel "B" trip logic sends an isolation signal to close the outboard isolation valves. The channels are arranged so that any one of the channels can initiate isolation.

High differential flow in the RWC system is sensed by a differential flow switch. Flow from the reactor is sensed and compared with the sum of the flows returning to the feedwater line and to the condenser or radwaste system. This arrangement is shown in figure 7.3-7. Tripping of the differential flow switch initiates isolation of the cleanup system. Isolation signals, based upon the high differential flow, are considered nonessential for achieving either a group B or C isolation. This isolation function is not an engineered safety feature. The cleanup system isolation arrangements are shown on drawing no. H-16188. The high differential flow signal to the RWC isolation valves may be bypassed for up to 2 hours during periods of system restoration, maintenance, or testing.

High differential temperature in the RWC system equipment room is sensed by 12 (6 pair) RTDs. Six of the RTDs monitor RWC area ventilation air inlet, and the remaining six RTDs monitor RWC area ventilation air outlet. Cables are routed from the RTDs to trip units located in the MCR. The trip units for RWC area ventilation air outlet temperature trip on high ambient temperature. Analog signals from 12 trip units are further routed to 6 trip units which trip on high differential temperature. This arrangement is illustrated in figure 7.3-8. Each trip unit is arranged as one channel. One ambient temperature trip unit plus one differential temperature trip unit form a trip system. The tripping of either trip unit within a trip system initiates isolation. This instrumentation is part of the ATTS, which is discussed in section 7.18.

Isolation of the reactor water cleanup system upon initiation of the standby liquid control system prevents dilution and removal of the boron solution by the reactor water cleanup system. Standby liquid control system initiation begins when the standby liquid control pump receives a start signal. Initiation of the standby liquid control system isolates the group 5 reactor water cleanup outboard isolation valve.

High ambient temperature in the suppression pool area is sensed by four RTDs. Vent air inlet and outlet high differential temperature in the suppression pool area is sensed by eight RTDs. Cables are routed from the 12 RTDs to 12 trip units located in the MCR. The eight vent air inlet and outlet trip unit analog output signals are further routed to four differential temperature trip units. One ambient temperature trip unit plus one vent air differential temperature trip unit form a trip system. A trip of either trip unit of a trip system initiates a timer in the MCR. Two trip systems with associated timers are allocated to the RCIC system, while the two remaining are allocated to the HPCI system. Isolation of the RCIC or HPCI steam lines occurs when one of the associated time delay relays runs out. The RTDs and trip units are part of the ATTS, which is discussed in section 7.18.

Four thermocouples, which are routed to a temperature switch, are located near the high ambient temperature RTDs; eight thermocouples (four pair routed to four differential temperature switches) are located near the high differential temperature RTDs. A trip from these switches initiates alarms in the MCR.

Channel and logic relays are high reliability relays equal to type HFA relays made by GE. The relays are selected so that the continuous load does not exceed 50% of the continuous duty rating.

Reactor vessel steam dome low pressure interlock/permissive is sensed by two transmitters connected to different taps on the RPV, and isolates the shutdown cooling portion of the RHR system on high pressure for equipment protection and provides an interlock to the low pressure coolant injection mode on the RHR system.

7.3.4.9 Environmental Capabilities

The physical and electrical arrangement of the primary containment and reactor vessel isolation control system was selected so that no single physical event prevents isolation. The location of group A and group B valves inside and outside the primary containment provides assurance that the control system for at least one valve on any line penetrating the primary containment remains capable of automatic isolation. Electrical cables for isolation valves in the same line are routed separately. Motor operators for valves inside the primary containment are of the totally enclosed type; those outside the primary containment have weatherproof-type enclosures. Solenoid valves, whether used for direct valve isolation or as an air pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for normal operations. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high-radiation areas have radiation-resistant insulation. Shielded cables are used where necessary to eliminate interference from magnetic fields.

Special consideration has been given to isolation requirements during a loss-of-coolant accident (LOCA) inside the drywell. Components of the primary containment and reactor vessel isolation control system that are located inside the primary containment and that must operate during a LOCA are the cables, control mechanisms, and valve operators of isolation valves inside the drywell. These isolation components are required to be functional in a LOCA environment.

Electrical cables are selected with insulation designed for this service. Closing mechanisms and valve operators are considered satisfactory for use in the isolation control system only after completion of environmental testing under LOCA conditions or submission of evidence from the manufacturer describing the results of suitable prior tests.

Verification that the isolation equipment has been designed, built, and installed in conformance to the specified criteria is accomplished through quality control and performance tests in the vendor's shop or after installation at the plant before startup, during startup, and thereafter during the service life of the equipment.

7.3.5 SAFETY EVALUATION

The primary containment and reactor vessel isolation control system, in conjunction with other protection systems, is designed to provide timely protection against the onset and consequences of accidents involving the gross release of radioactive material from the fuel and nuclear system process barriers. The objective of HNP-2-FSAR chapter 15, Safety Analysis, is to identify and evaluate postulated events resulting in gross failure of the fuel barrier and the nuclear system process barrier. The consequences of such gross failures are described and evaluated in the safety analysis.

Design procedures have been to select tentative isolation trip settings, based on process safety limits, that are far enough above or below normal operating levels that spurious isolation and operating inconvenience are avoided. It is then verified by analysis that the release of radioactive material following postulated gross failures of the fuel and the nuclear system process barrier is kept within acceptable bounds. Trip setting selection is based on operating experience and is constrained by the safety design basis and the safety analysis.

HNP-2-FSAR chapter 15 shows that the actions initiated by the primary containment and reactor vessel isolation control system, in conjunction with other safety systems, are sufficient to prevent releases of radioactive material from exceeding the guideline values of published regulations.

Temperatures in the spaces occupied by various steam lines outside the primary containment have spatial dependence and provide inputs to the primary containment and reactor vessel isolation control system. The large number of temperature sensors and their location in the equipment areas assures that a significant break is detected rapidly and accurately.

HNP-2-FSAR chapter 15 evaluates a gross breach in a main steam line outside the primary containment during operation at rated power. The evaluation shows that the main steam lines are automatically isolated in time to prevent a release of radioactive material in excess of the guideline values of published regulations and to prevent the loss of coolant from being great enough to allow uncovering of the core. These results are true even if the longest closing time of the valve is assumed.

The shortest time in which the MSIVs are capable of closing is 3 s. The AOO resulting from a simultaneous closure of all MSIVs in 3 s during reactor operation at rated power is considerably less severe than the AOO resulting from inadvertent closure of the turbine stop valves (which occurs in a small fraction of 1 s) coincident with failure of the turbine bypass system. The RPS is capable of accommodating the AOO resulting from the inadvertent closure of the MSIVs (HNP-2-FSAR chapter 15).

Because essential variables are monitored by four channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate closure of automatic isolation valves, no single failure, maintenance operation, calibration operation, or test can prevent the system from achieving isolation. An analysis of the isolation control system shows that the system does not fail to respond to essential variables as a result of single electrical failures such as short circuits, grounds, and open circuits. A single trip system trip is the result of these failures. Isolation is initiated upon a trip of the remaining trip system. For some of the exceptions to the usual logic arrangement a single failure could result in inadvertent isolation of a line. With respect to the release of radioactive material from the nuclear system process barrier, such inadvertent valve closures are in the safe direction and do not pose any safety problems.

The redundancy of channels provided for all essential variables provides a high probability that whenever an essential variable exceeds the isolation setting, the system initiates isolation. In the unlikely event that all channels for one essential variable in one trip system fail in such a way that a system trip does not occur, the system could still respond properly as other monitored variables exceed their isolation settings.

The sensors circuitry, and logics used in the primary containment and reactor vessel isolation control system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the isolation control system.

The various power supplies used for the isolation system logic circuitry and for valve operation provide assurance that the required isolation can be effected in spite of power failures. If ac for valves inside the primary containment is lost, dc is available for operation of valves outside the primary containment. The MSIV control arrangement is resistant to both ac and dc power failures. Because both solenoid operated pilot valves must be deenergized, loss of a single power supply neither causes inadvertent isolation nor prevents isolation if required. The logic circuitry for each channel is powered from the separate sources available from the RPS buses or an ac power supply. Loss of a power source here results in a single trip system trip. In no case does a loss of a single power supply prevent isolation when required.

All instruments, valve closing mechanisms, and cables of the isolation control system can operate under the most unfavorable environmental conditions associated with normal operation. The discussion of the effects of rapid nuclear system depressurization on level measurement given in section 7.2 is equally applicable to the RPV low water level transmitters used in the primary containment and reactor vessel isolation control system. The differential temperature, pressure, differential pressure, and level switches and transmitters, cables, and valve closing mechanisms used were selected with ratings that make them suitable for use in the environment in which they must operate.

The special considerations (treated in the description portion of this section) made for the environmental conditions resulting from a LOCA inside the drywell are adequate to ensure operability of essential isolation components located inside the drywell.

The wall of the primary containment effectively separates adverse environmental conditions which might otherwise affect both isolation valves in a line. The location of isolation valves on either side of the wall decouples the effects of environmental factors with respect to the ability to isolate any given line. The previously discussed electrical isolation of control circuitry prevents failures in one part of the control system from propagating to another part. Electrical transients have no significant effect on the functioning of the isolation control system.

The motive force for closing each MSIV is derived from both a source of pneumatic pressure and the energy stored in a spring. Either energy source is capable, alone, of closing the valve. None of the valves rely on continuity of any sort of electrical power to achieve closure in response to essential safety signals. Total loss of the power used to control the valves would result in closure.

Calibration and test controls for pressure and level switches and transmitters/trip units are located on the switches and transmitters/trip units themselves. These switches and transmitters are located in the turbine building and reactor building, and the trip units are located in the MCR. The location of calibration and test controls in areas under the control of the plant operator or supervisory personnel reduces the probability that operational reliability will be degraded by operator error.

7.3.6 INSPECTION AND TESTING

The primary containment and reactor vessel isolation control system is testable during reactor operation. Isolation valves can be tested to assure that they are capable of closing by operating manual switches in the MCR and observing the position lights and any associated process effects. The channel and trip system responses can be functionally tested by applying test signals to each channel and observing the trip system response. Testing of the MSIVs is discussed in section 4.6.

<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

TABLE 7.3-2 (SHEET 1 OF 3)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM ISOLATION SETPOINTS

Isolation Function	Sensor	Trip Setting
RPV water level-low (level 3)[c]	Differential pressure transmitter/trip unit	(a)
RPV water level-low low low (level 1)[c]	Differential pressure transmitter/trip unit	(a)
Main steam line radiation - high	Radiation monitor	≤ 3 x background
Main steam line flow - high	Differential pressure transmitter/trip unit	(a)
Main steam line pressure - low	Pressure switch	(a)
Drywell pressure - high	Pressure transmitter/trip unit	(a)
RCIC equipment room ambient temperature - high	RTD/trip unit	(a)
RCIC turbine steam line pressure - low	Pressure transmitter/trip unit	(a)
HPCI equipment room ambient temperature - high	RTD/trip unit	(a)
HPCI turbine steam line pressure - low	Pressure transmitter/trip unit	(a)
Reactor building ventilation exhaust radiation - high	Radiation monitor	(a)
Refueling floor ventilation exhaust radiation - high	Radiation monitor	(a)
RWC equipment room ambient temperature - high	RTD/trip unit	(a)

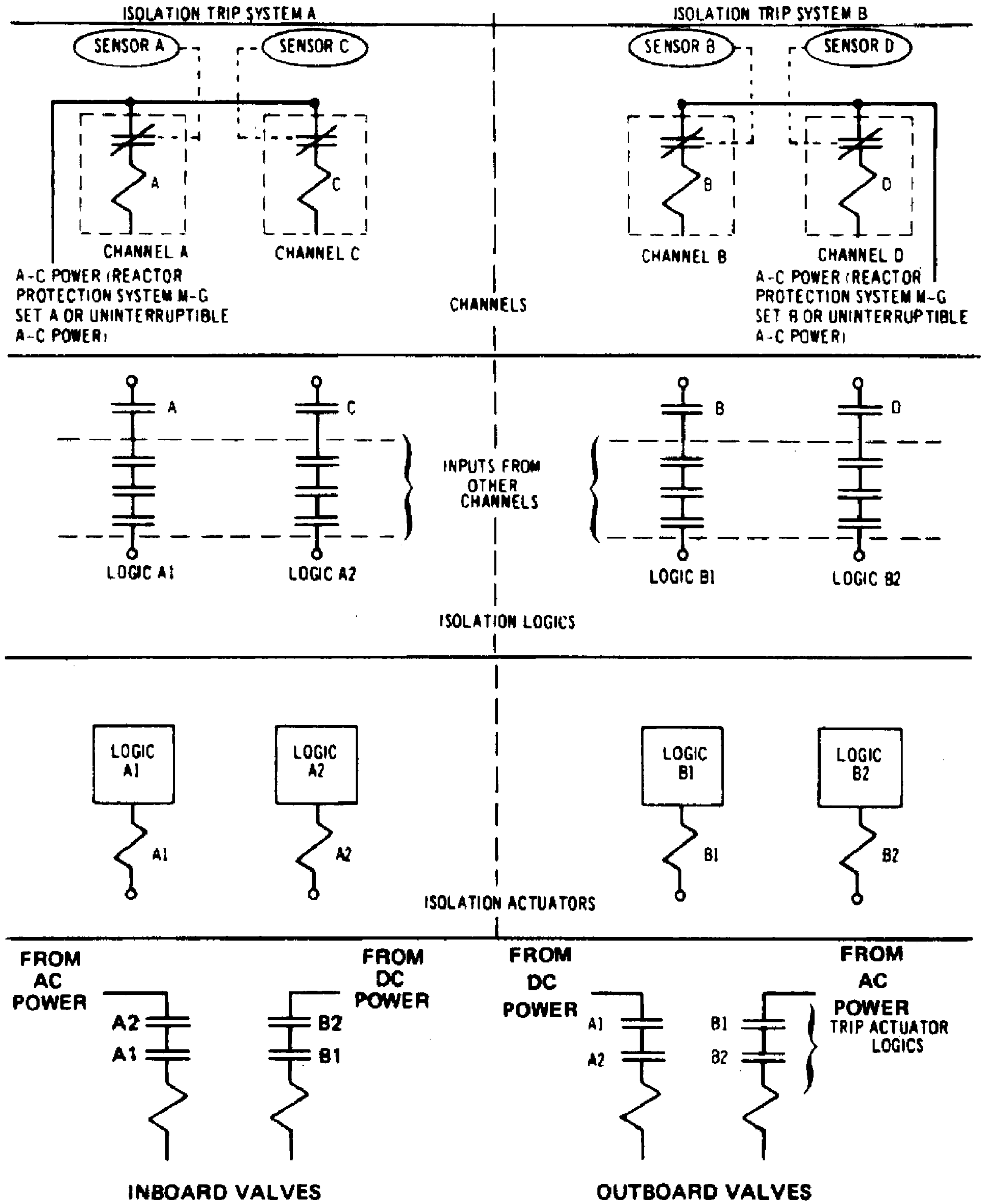
TABLE 7.3-2 (SHEET 2 OF 3)

Isolation Function	Sensor	Trip Setting
Main steam line tunnel temperature - high	RTD/trip unit	(a)
Reactor pressure (shutdown cooling mode) - high	Pressure transmitter/trip unit	(a)
RWC equipment room ventilation air in/out differential temperature - high	Differential temperature/trip unit (RTDs)	(a)
Main turbine condenser vacuum - low	Pressure switch	(a)
RCIC turbine exhaust diaphragm pressure - high	Pressure transmitter/trip unit	(a)
HPCI turbine exhaust diaphragm pressure - high	Pressure transmitter/trip unit	(a)
RCIC turbine steam line flow (upstream and downstream elbow taps) - high	Differential pressure transmitter/trip unit	(a)
RCIC turbine steam instrument line failure	Differential pressure transmitter/trip unit	-100 in. H_2O[b]
HPCI turbine steam line flow - high	Differential pressure transmitter/trip unit	(a)
HPCI turbine steam instrument line failure	Differential pressure transmitter/trip unit	-100 in. H_2O[b]
RCIC suppression pool area ambient temperature - high	RTDs/trip unit	(a)
RCIC suppression pool area ventilation air in/out differential temperature - high	Differential temperature/trip unit (RTDs)	(a)

TABLE 7.3-2 (SHEET 3 OF 3)

Isolation Function	Sensor	Trip Setting
RPV water level-low low (level 2)[c]	Differential pressure transmitter/trip unit	(a)
Drywell high radiation	Radiation indicating switch	(a)
RCIC suppression pool area ambient temperature - time delay relays	Timer	(a)
HPCI pipe penetration room temperature - high	RTD/trip unit	(a)
HPCI suppression pool area ambient temperature - high	RTD/trip unit	(a)
HPCI suppression pool area ventilation air in/out differential temperature - high	Differential temperature/trip unit (RTDs)	(a)
HPCI suppression pool ambient temperature-time delay relays	Timer	(a)
Turbine building area temperature - high	Temperature switch	(a)

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. The value given is actual trip setpoint, see HNP-1 Instrument Setpoint Index.
c. Referenced to instrument zero.



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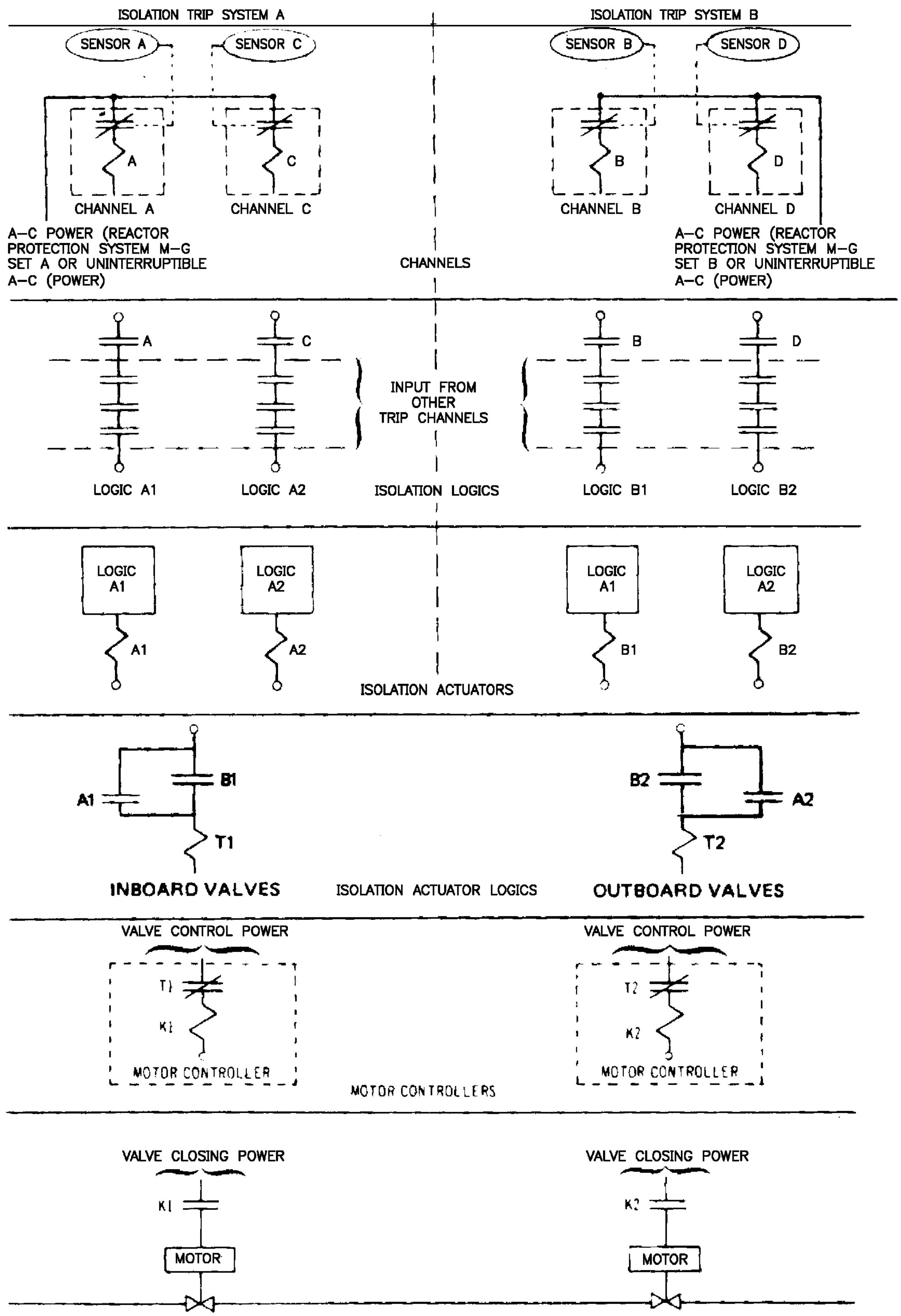
TYPICAL ISOLATION CONTROL SYSTEM FOR MAIN STEAM ISOLATION VALVES

FIGURE 7.3-1



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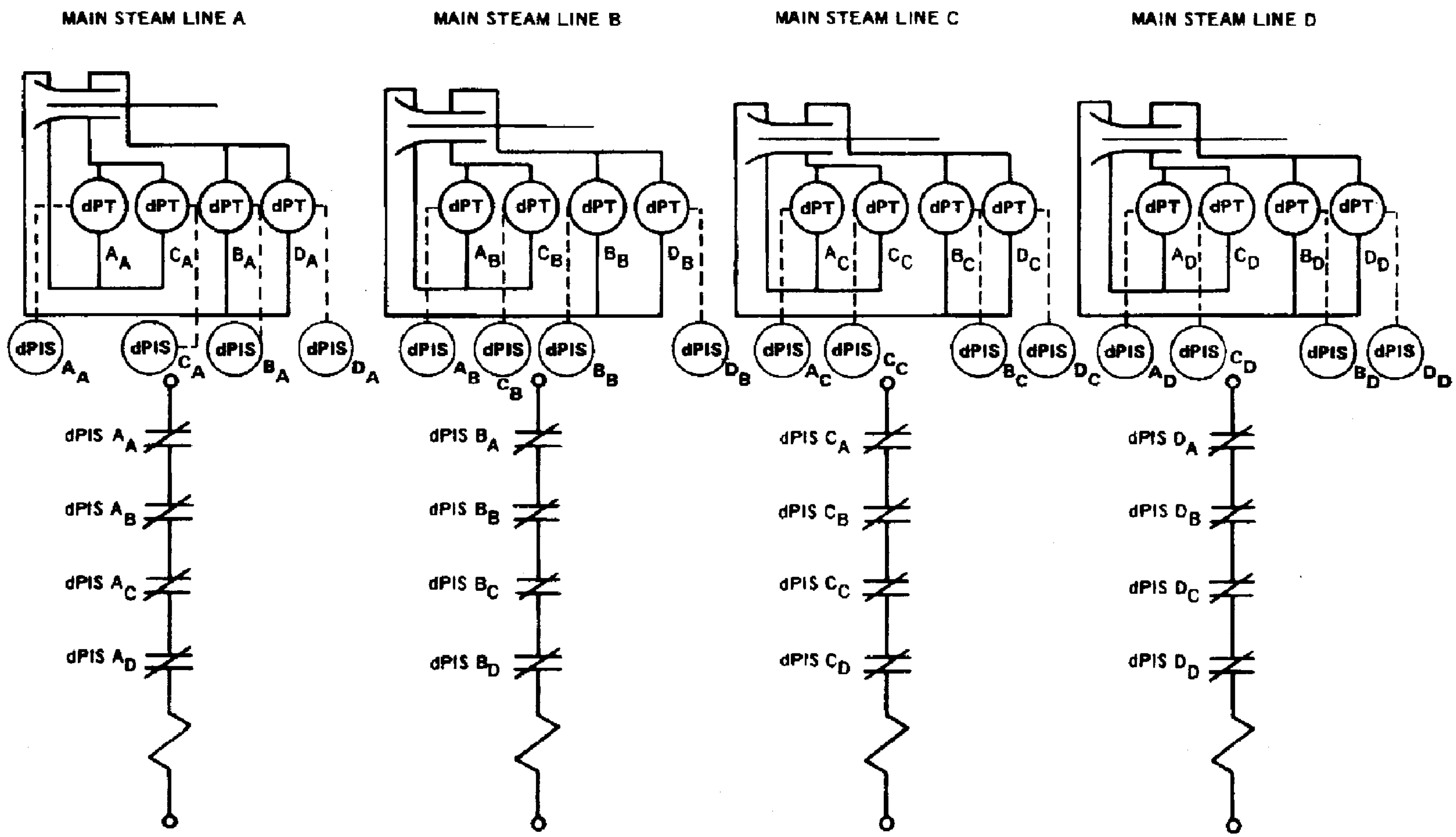
TYPICAL ISOLATION CONTROL SYSTEM USING MOTOR-OPERATED VALVES

FIGURE 7.3-2



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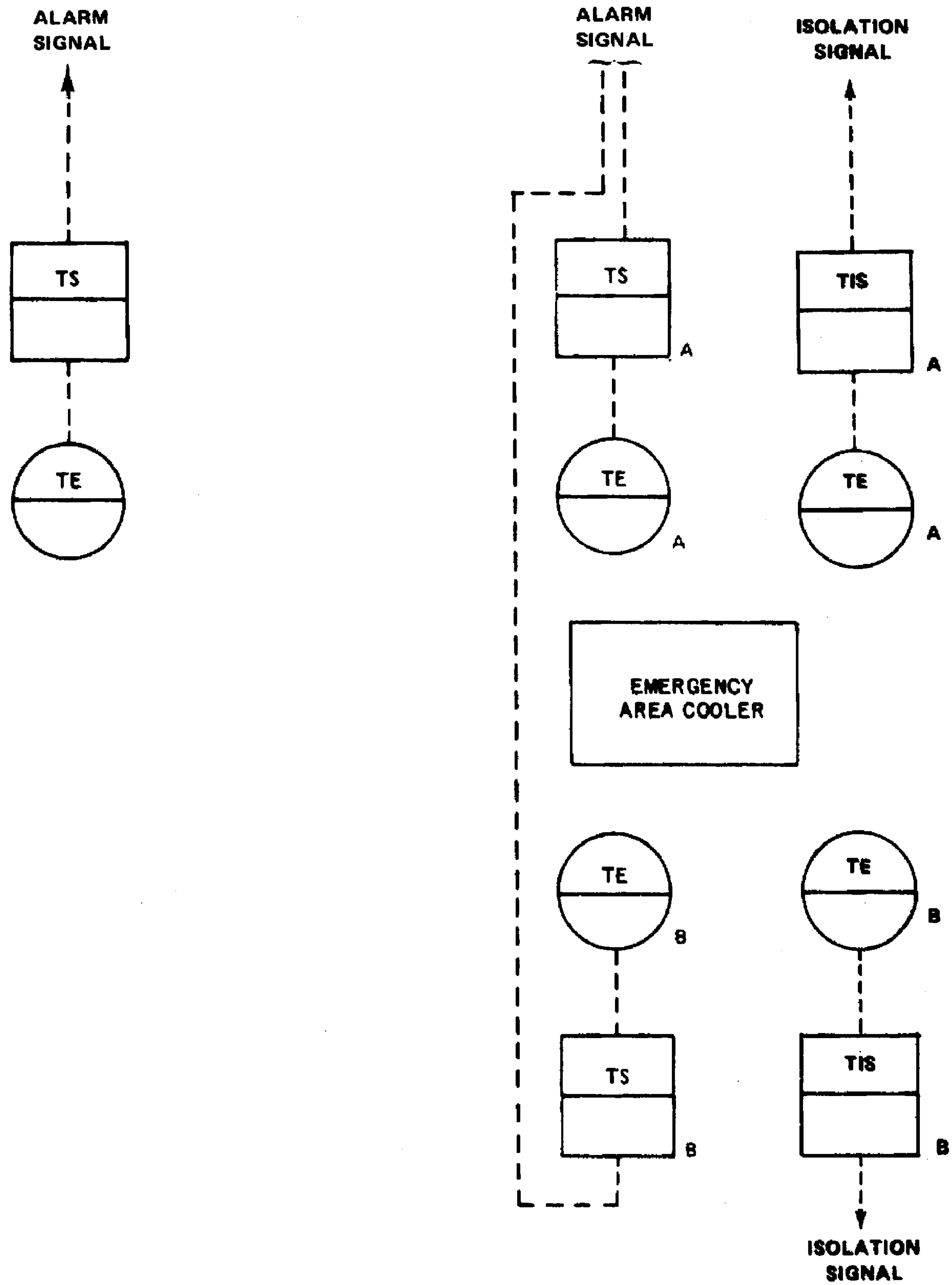
MAIN STEAM LINE HIGH FLOW CHANNELS

FIGURE 7.3-4



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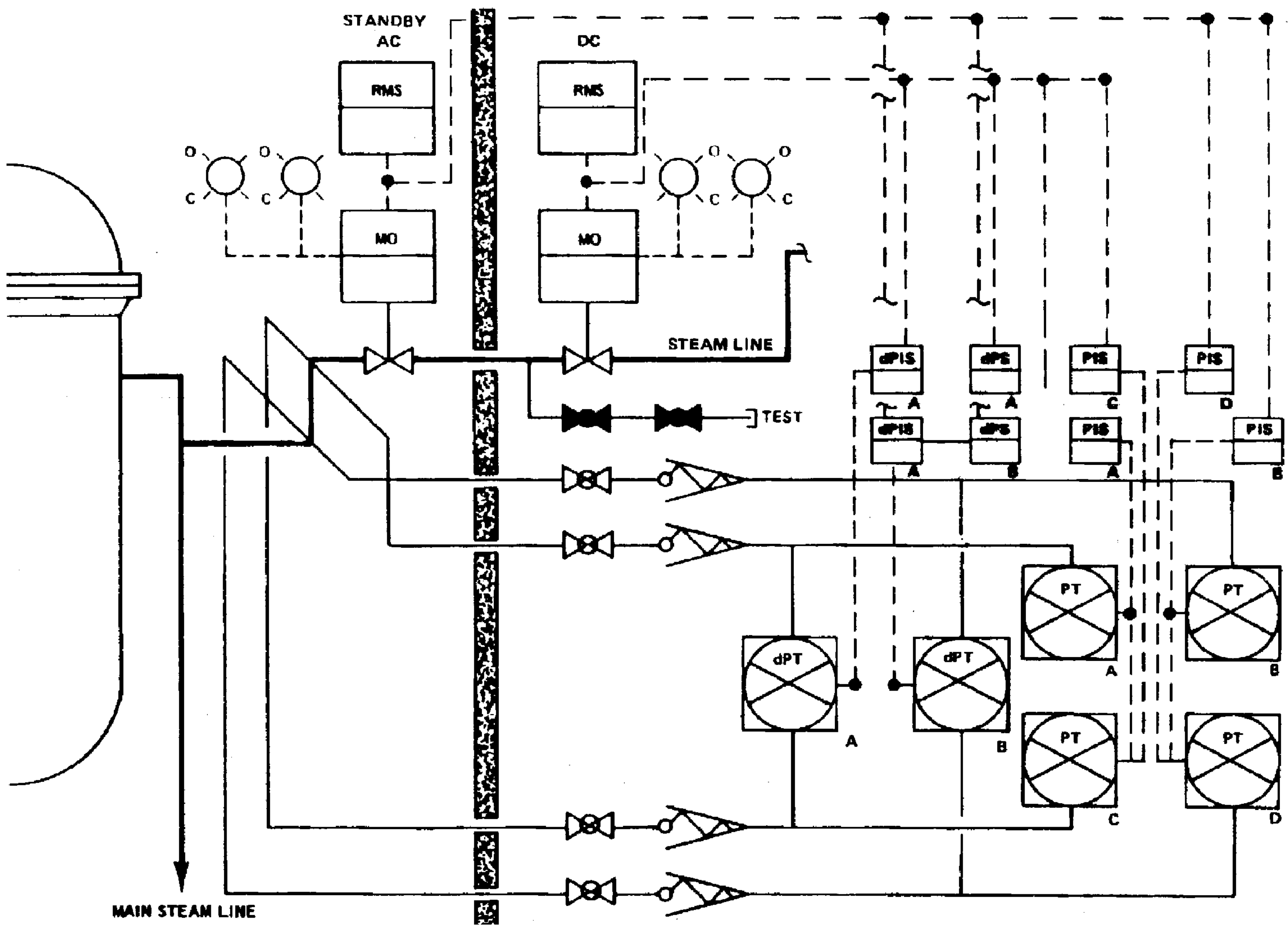
HPCI OR RCIC ROOM TEMPERATURE
DETECTOR ARRANGEMENT

FIGURE 7.3-5



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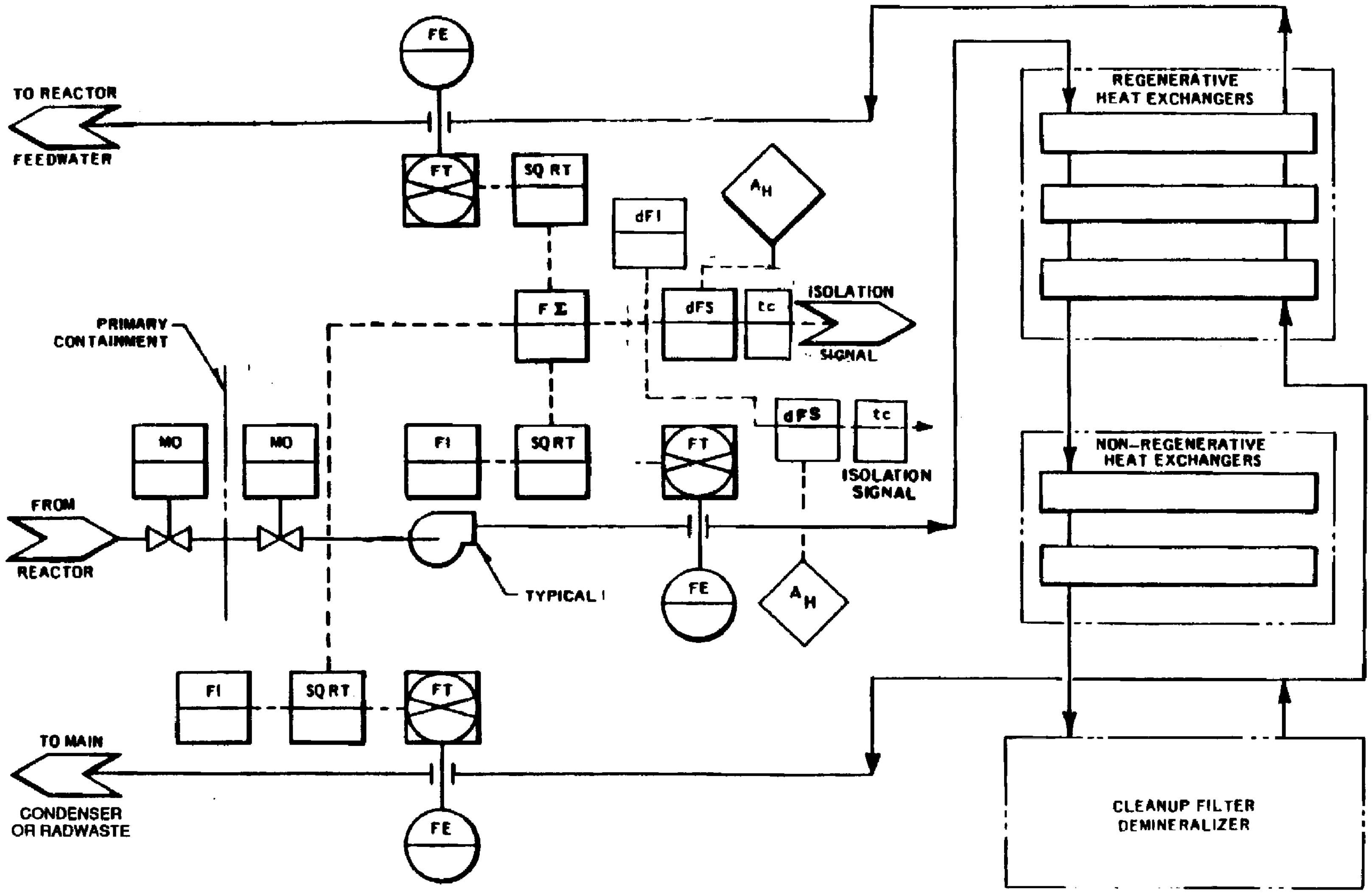
TYPICAL ELBOW FLOW-SENSING ARRANGEMENT

FIGURE 7.3-6



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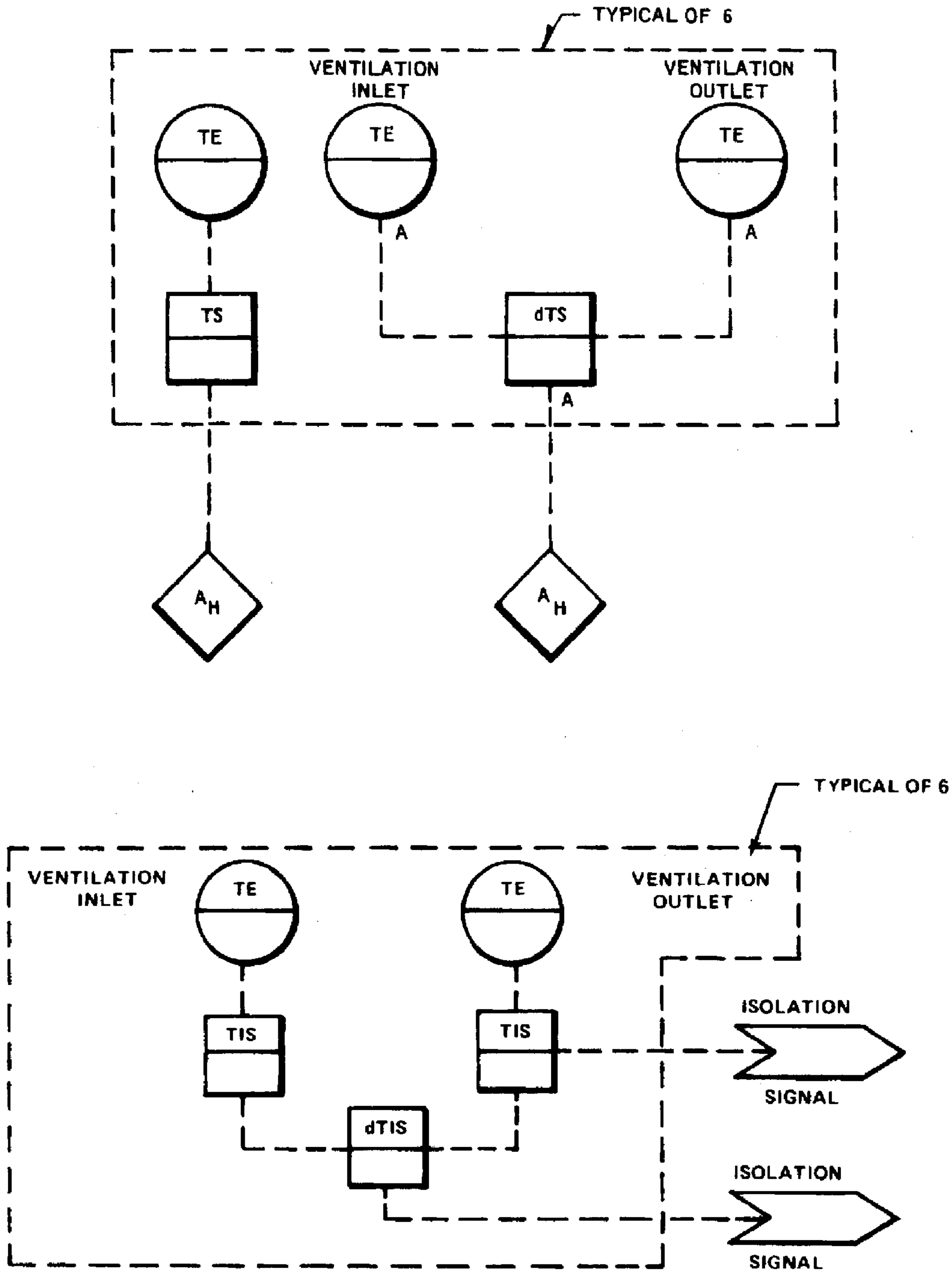
REACTOR WATER CLEANUP BREAK DETECTION BY DIFFERENTIAL FLOW MEASUREMENT

FIGURE 7.3-7



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REACTOR WATER CLEANUP BREAK DETECTION BY HIGH AMBIENT AND HIGH DIFFERENTIAL TEMPERATURE MEASUREMENT

7.3-8

7.4 EMERGENCY CORE COOLING SYSTEM CONTROL AND INSTRUMENTATION

7.4.1 SAFETY OBJECTIVE

The controls and instrumentation for the emergency core cooling system (ECCS) initiate appropriate responses from the various cooling systems so that the fuel is adequately cooled under abnormal or accident conditions. The cooling provided by the systems restricts the release of radioactive materials from the fuel by limiting the extent of fuel damage following situations in which reactor coolant is lost from the nuclear system.

Even after the reactor is shut down from power operation by the full insertion of all control rods, heat continues to be generated in the fuel as radioactive fission products decay. An excessive loss of reactor coolant allows the fuel temperature to rise, cladding to melt, and fission products in the fuel to be released. If the temperatures in the reactor rise to a sufficiently high value, a metal (zirconium) water reaction occurs, which releases energy. Such a reaction increases the pressure inside the nuclear system and the primary containment. This threatens the integrity of the barriers which are relied upon to prevent the uncontrolled release of radioactive material. The ECCS controls and instrumentation prevent such a sequence of events by actuating core cooling systems in time to limit fuel temperatures to acceptable levels.

7.4.2 SAFETY DESIGN BASES

A. Controls and instrumentation provide precise, reliable, automatic control of the ECCS. To prevent fuel-cladding damage or core deformation, the allowable cladding temperature does not exceed 2200°F.

B. Controls and instrumentation, with precision and reliability, initiate and control the ECCS with sufficient timeliness to prevent no more than a small fraction of the core from approaching temperatures at which a gross release of fission products occurs.

C. To meet the precision requirements of safety design bases A and B, the controls and instrumentation respond to conditions that indicate the potential inadequacy of core cooling, regardless of the physical location of the defect causing the inadequacy.

D. To place limits on the degree to which safety is dependent on operator judgment in time of stress, the following safety design bases are specified:

   1. Appropriate response of the ECCS is initiated automatically by control systems so that no decision or manipulation of controls is required of plant operations personnel.

2. Intelligence of the response of the ECCS is provided to the operator by main control room (MCR) instrumentation so that faults in the actuation of safety equipment can be diagnosed.

3. Facilities for manual actuation of the ECCS are provided in the MCR so that operator judgment and action is possible, yet administratively reserved for the remedy of a deficiency in the automatic actuation of the safety equipment.

E. To meet the reliability requirements of safety design bases A and B, the following safety design bases are specified:

1. No single failure, maintenance, calibration, or test operation prevents the integrated ECCS operations from providing adequate core cooling.

2. Any installed means of manually interrupting ECCS availability is under the physical control of the MCR operator or other supervisory personnel.

3. The power supplies for ECCS controls and instrumentation are chosen so that core cooling can be accomplished concurrently with a loss-of-offsite auxiliary ac power.

4. The physical events that accompany a loss-of-coolant accident (LOCA) will not interfere with the ability of ECCS controls and instrumentation to function properly.

5. Earthquake ground motion will not impair the ability of the control and instrumentation of the essential ECCS to function properly.

F. To provide the operator with the means to verify ECCS availability, it is possible to test the responses of the controls and instrumentation to conditions representative of abnormal or accident situations.

G. In addition to the safety design bases listed above, the ECCS network conforms to the Institute of Electrical and Electronics Engineers (IEEE) Proposed Criteria for Nuclear Power Plants Protection Systems (IEEE 279). In case of conflict, IEEE 279 prevails.

7.4.3 DESCRIPTION

7.4.3.1 Identification

The ECCS controls and instrumentation are identified as that equipment required for the initiation and control of the following subsystems:

- High-pressure coolant injection (HPCI) system.
- Automatic depressurization system (ADS).
- Core spray (CS) system.
- Low-pressure coolant injection (LPCI) (an operating mode of the residual heat removal (RHR) system).

The equipment involved in the control of these systems includes automatic valves, turbine pump controls, electric pump controls, and relief valve controls and the switches, transmitters/trip units, contacts, and relays that make up sensory logic channels. Certain automatic isolation valves are not included in this description because they are described in section 7.3.

The ECCS initiation and control instrumentation can be conveniently broken into two parts: the incident detection circuitry (IDC) and the control instrumentation. The IDC includes those channels which detect a need for core cooling systems operation and the corresponding logic systems which initiate the proper ECCS response.

To assure the functional capabilities of the ECCS during and after earthquake ground motions, the controls and instrumentation for each of the systems are designed as Seismic Class 1 equipment. A typical actuation logic for the ECCS is shown in figure 7.4-1. A summary of the initiating signals for ECCS actuation is given in figure 6.1-2.

7.4.3.2 HPCI System Control and Instrumentation

7.4.3.2.1 Identification and Physical Arrangement

When actuated, the HPCI system pumps water from either the condensate storage tank (CST) or the suppression chamber to the reactor vessel via the feedwater lines. The HPCI system includes one turbine-driven pump, one dc motor-driven auxiliary oil pump, one gland-seal condenser dc condensate pump, one gland condenser dc blower, automatic valves, control devices for this equipment, sensors, and logic circuitry. The arrangement of equipment and control devices is shown on drawing nos. H-16332 and H-16333.

Pressure and level switches and transmitters used in the HPCI system are located on racks or mounted locally in the reactor building. The only operating component of the HPCI system that is located inside the primary containment is one of the two HPCI system turbine steam supply line isolation valves. The rest of the HPCI system control and instrumentation components are located outside the primary containment. Cables connect the sensors to control circuitry in the MCR. Although the system is arranged to allow a full-flow functional test of the system during normal reactor power operation, the system is declared inoperable while in the test mode. The test controls are arranged so that the test valve returns automatically to the closed position if an initiation signal occurs during a test.

7.4.3.2.2 HPCI System Initiation Signals and Logic

Reactor pressure vessel (RPV) water level 2 and primary containment (drywell) high pressure are the two functions, either of which can automatically start the HPCI system as indicated on drawing nos. H-19947, H-19948, H-19950, and H-19951. RPV water level 2 is an indication that reactor coolant is being lost and that the fuel is in danger of being overheated. Primary containment high pressure is an indication that a breach of the nuclear system process barrier has occurred inside the drywell.

The scheme used for initiating the HPCI system is shown in figure 7.4-2. One system logic actuates the system upon receipt of a water level 2 signal, and the other actuates upon receipt of a high drywell pressure signal. Either system logic can start the HPCI system. The HPCI initiation system is powered by a reliable dc bus.

Instrument settings for the HPCI system controls and instrumentation are listed in table 7.4-1. The RPV water level 2 setting for HPCI system initiation is selected high enough above the active fuel to start the HPCI system in time to provide added protection to the fuel cladding for events involving loss-of-coolant inventory. The water level setting is far enough below normal levels that spurious HPCI system startups are avoided. The primary containment high-pressure setting is selected to be as low as possible without inducing spurious HPCI system startup.

7.4.3.2.3 HPCI System Initiating Instrumentation

RPV water level 2 is monitored by four level transmitters that sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual height of water in the vessel. Two lines, attached to taps above and below the water level on the reactor vessel, are required for the differential pressure measurement for each pair of transmitters. The two pair of lines terminate outside the primary containment and inside the reactor building. They are physically separated from each other and tap off the reactor vessel at widely separated points. (See drawing no. H-16063.) These same lines are also used for pressure and water level instruments for other systems. The level transmitters for the HPCI system are arranged in pairs; each pair senses the level from one pair of pipelines. Cables are routed from the transmitters to trip units located in the MCR. Either pair of level transmitters/trip units sensing RPV water level 2 can initiate the HPCI system. This arrangement assures that no single event can prevent HPCI system initiation from RPV water level 2. Temperature compensating columns are used to increase the accuracy of level measurements. The instrumentation mentioned above is a part of the analog transmitter trip system (ATTS), which is discussed in section 7.18.

Primary containment pressure is monitored by four pressure transmitters which are mounted locally outside the drywell but inside the reactor building. Cables are routed from the transmitters to trip units located in the MCR. Pipes that terminate in the reactor building allow the transmitters to communicate with the drywell interior. The transmitters/trips are grouped in pairs similar to the level sensors and electrically connected so that no single event can prevent the initiation of the HPCI system due to primary containment high pressure. This instrumentation is part of the analog transmitter trip system (ATTS), which is discussed in section 7.18.

7.4.3.2.4 HPCI System Turbine and Turbine Auxiliaries Control

The HPCI system is initiated automatically after the receipt of an RPV low water level 2 signal or a high-pressure signal and produces the design flowrate within 75 s. The controls then function to provide design makeup water flow to the reactor vessel until the amount of water delivered to the reactor vessel causes the RPV water level 8 trip, at which time the HPCI system automatically shuts down. The controls are arranged to allow remote-manual startup, operation, and shutdown.

The HPCI turbine is functionally controlled as shown on drawing no. H-19949. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a HPCI system flow signal and adjusts the turbine steam control valve so design HPCI system pump discharge flowrate is obtained. Manual control of the governor is possible in the test mode, but the governor automatically returns to automatic control upon receipt of a HPCI system initiation signal. Drawing no. H-19949 shows the various modes of turbine control. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the HPCI system pump discharge line. The governor controls the position of the hydraulic operator on the turbine control valve which, in turn, controls the steam flow to the turbine. Hydraulic pressure is supplied for both the turbine control valve and the turbine stop valve by the auxiliary dc-powered oil pump during startup and then by the shaft-driven hydraulic oil pump when the turbine reaches operating speed.

Upon receipt of an initiation signal, the auxiliary oil pump starts, providing hydraulic pressure for the turbine stop valve, the turbine control valve hydraulic operator, and the "c" control line between the hydraulic actuator and the remote servo. Although there is no flow at first in the HPCI system, the turbine control valves are maintained closed by the HPCI turbine's electronic control system during the initial portion of the turbine start transient. This prevents rapid speedup of the turbine, thus reducing the possibility of an overspeed trip. As hydraulic oil pressure is developed, the turbine stop valve and the turbine control valve open simultaneously, and the turbine accelerates in accordance with the increasing speed demand of the turbine control ramp generator circuit. As the HPCI flow increases, the flow signal automatically overrides the ramp generator circuit to maintain design flow.

The turbine is automatically or manually shut down by tripping the turbine stop valve closed if any of the following conditions are detected:

- Turbine overspeed.
- High turbine exhaust pressure.
- Low pump suction pressure.
- RPV water level 8.
- Isolation and leak detection functions.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust line. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump which could place it out of service. A turbine trip is initiated for these conditions so that if the causes of the abnormal conditions can be found and corrected, the system can be quickly restored to service. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so close that damage occurs before the turbine is shut down. Turbine overspeed is detected by a standard turbine overspeed mechanical hydraulic device. Two pressure transmitters are used to detect high turbine exhaust pressure. Cables are routed from these transmitters to trip units located in the MCR. Either transmitter/trip unit can initiate turbine shutdown. One pressure transmitter/trip unit is used to detect low HPCI system pump suction pressure. Cables are routed from this transmitter to a trip unit located in the MCR. This pressure instrumentation is part of ATTS, which is discussed in section 7.18.

High water level (level 8) in the reactor vessel indicates that the HPCI system has performed satisfactorily in providing makeup water to the reactor vessel. The RPV water level 8 setting which trips the turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters/trip units trip to initiate a turbine shutdown. A number of HPCI system parameters are measured and used with suitable trip settings to provide isolation protection for the system. Also these functions form an integral part of the overall plant leak detection system. When isolation occurs, the HPCI turbine stop valve is closed. These isolation and leak detection functions are described in paragraphs 7.3.4.7 and 7.3.4.8. The level instrumentation mentioned above is part of the ATTS, which is discussed in section 7.18.

The control scheme for the turbine auxiliary oil pump is shown on drawing no. H-19949. The controls are arranged for automatic or manual control. Upon receipt of a HPCI system initiation signal, the auxiliary oil pump starts and provides hydraulic pressure to open the turbine stop valve and the turbine control valve. As the turbine gains speed, the shaft-driven oil pump begins to supply hydraulic pressure. After about 1/2 min during an automatic turbine startup, the pressure supplied by the shaft-driven oil pump is sufficient; the auxiliary oil pump automatically stops upon receipt of a high oil pressure signal. Should the shaft-driven oil pump malfunction, causing oil pressure to drop, the auxiliary oil pump restarts automatically.

Operation of the barometric condenser components (barometric condenser condensate pump (dc), barometric condenser blower (dc), and barometric condenser water level instrumentation) prevents out-leakage from the turbine shaft seals. Startup of this equipment is automatic, as shown on drawing nos. H-19952 and H-19953. Manual startup is also available. Failure of this equipment will not prevent the HPCI system from providing water to the reactor vessel.

7.4.3.2.5 HPCI System Valve Control

All automatic valves in the HPCI system are equipped with remote-manual test capability so that the entire system can be operated from the MCR. Motor-operated valves are provided with appropriate limit or torque switches to turn off the motors when the full-open or full-closed positions are reached. Valves that are automatically closed on isolation or turbine trip signals are equipped with remote manual reset devices so that they cannot be reopened without operator action. All essential components of the HPCI system controls operate independent of ac power.

To ensure that the HPCI system can be brought to design flowrate within 75 s from the receipt of the initiation signal, the following maximum operating times for essential HPCI system valves are provided by the valve operating mechanisms:

- HPCI system turbine steam supply valve ≤ 75 s
- HPCI system pump discharge valve ≤ 35 s
- HPCI system pump minimum flow bypass valve ≤ 10 s

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. Because the two HPCI system steam supply line isolation valves are normally open and because they are intended to isolate the HPCI system steam line in the event of a break in that line, the operating time requirements for them are based on isolation specifications described in section 7.3. A normally closed dc motor-operated isolation valve is located in the turbine steam supply line just upstream of the turbine stop valve. The control scheme for this valve is shown on drawing no. H-19950. Upon receipt of a HPCI system initiation signal, this valve opens and remains open until closed by operator action from the MCR.

Two normally open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an ac motor. The valve outside the drywell is controlled by a dc motor. The control diagram is shown on drawing nos. H-19947 and H-19948. Because the valves are normally open with keylocked control switches and alarmed when not fully open, no initiation signal will open the valves if they are closed; this also prevents automatic opening without the proper steam line draining and prewarming. The valves automatically close upon receipt of a HPCI system turbine steam line high-flow signal, HPCI turbine high-exhaust diaphragm pressure signal, HPCI system turbine steam supply low-pressure signals, and leak detection temperature or differential temperature signal. The instrumentation for isolation is described in section 7.3, Primary Containment and Reactor Vessel Isolation Control System.

Three pump suction shutoff valves are provided in the HPCI system. One valve provides pump suction from the CST, the other two in series provide suction from the suppression chamber. The CST is the preferred source. All three valves are operated by dc motors. The control arrangement for all three valves is shown on drawing nos. H-19950 and H-19953. Although the CST suction valve is normally open, a HPCI system initiation signal opens the valve if the valve is closed. If the water level in the CST falls below a preselected level, the suppression chamber suction valves automatically open. When the suppression chamber valves are both fully open, the CST suction valve automatically closes. Two level switches are used to detect the CST low water level condition. Either switch can cause the suppression chamber suction valves to open. The suppression chamber suction valves also automatically open, and the CST suction valve closes if a high water level is detected in the suppression chamber.

Two level transmitters monitor the suppression chamber water level. Cables are routed from these transmitters to trip units located in the MCR. Either trip unit can initiate opening of the suppression chamber suction valves. If open, the suppression chamber suction valves automatically close upon receipt of the signals that initiate HPCI system steam line isolation. This instrumentation is part of the ATTS, which is discussed in section 7.18.

Two dc motor-operated HPCI system pump discharge valves in the pump discharge line are provided. The control schemes for these two valves are shown on drawing nos. H-19947 and H-19951. Both valves are arranged to open upon receipt of the HPCI system initiation signal. One valve remains open until closed by operator action in the MCR. The other will close automatically upon receipt of a turbine stop valve or steam supply valve closed signal.

To prevent damage by overheating at reduced HPCI system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, dc motor-operated valve whose control scheme is shown on drawing no. H-19951. At HPCI system high flow, the valve is closed; at low flow, the valve is opened. A differential pressure transmitter measures the pressure difference across a flow element in the HPCI system pump discharge line. Cables are routed from this transmitter to a trip unit located in the MCR. This trip unit provides input signals to the valve. There is also an interlock provided to shut the minimum flow bypass whenever the turbine is tripped. This is necessary to prevent drainage of the CST into the suppression pool. This flow instrumentation is part of ATTS, which is discussed in section 7.18.

To prevent the HPCI system steam supply line from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain line arrangement just upstream of the turbine supply valve. The control scheme is shown on drawing no. H-19952. The controls position valves so that during normal operation steam line drainage is routed to the main condenser. Upon receipt of a HPCI system initiation signal, the drainage path is isolated. The water level in the steam line drain condensate pot is controlled by a level switch and an air-operated solenoid valve which opens to allow condensate to flow out of the pot.

During test operation, the HPCI system pump discharge can be routed to the CST or the suppression pool. The dc motor-operated valves are installed in the pump discharge test lines. The piping arrangement is shown on drawing no. H-16333. The control scheme for the valves is shown on drawing nos. H-19948 and H-19951. Upon receipt of a HPCI system initiation signal, the valves close and remain closed. The valves are interlocked closed if either of the suppression chamber suction valves are not fully closed. Numerous indications pertinent to the operation and condition of the HPCI system are available to the plant operator. Drawing nos. H-16333, H-19953, and H-19954 show the various indications provided.

7.4.3.2.6 HPCI System Environmental Considerations

The only HPCI system control component located inside the primary containment that must remain functional in the environment resulting from a LOCA is the control mechanism for the inboard isolation valve on the HPCI system turbine steam line. The environmental capabilities of this valve are discussed in section 7.3, Primary Containment and Reactor Vessel Isolation Control System. The HPCI system control and instrumentation equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate.

7.4.3.3 ADS Control and Instrumentation

7.4.3.3.1 Identification and Physical Arrangement

Automatically controlled relief valves are installed on the main steam lines inside the primary containment. The valves are dual purpose in that they will relieve pressure by normal mechanical action or by automatic action of an electric-pneumatic control system (section 4.4, Pressure Relief System). The relief by normal mechanical action is intended to prevent overpressurization of the nuclear system. The depressurization by automatic action of the control system is intended to reduce nuclear system pressure during a LOCA in which the HPCI system is not adequate so that the CS system or LPCI can inject water into the reactor vessel. The automatic control and instrumentation equipment for the relief valves is described in this section. The controls and instrumentation for one of the relief valves are discussed. Other relief valves equipped for automatic depressurization are identical.

The control system, which is functionally illustrated on drawing no. H-19901, consists of pressure and water level sensors arranged in the logic system that control a solenoid-operated pilot air valve. The solenoid-operated pilot valve controls the pneumatic pressure applied to a piston operator which controls the relief valve directly. An accumulator is included with the control equipment to store pneumatic energy for relief valve operation. The accumulator is sized to provide air for five actuations of the pilot valve following failure of the pneumatic supply to the accumulator. Cables from the sensors lead to the MCR where the logic arrangements are formed in a cabinet. The electrical control circuitry is powered by dc from the plant batteries. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability in the event of an electrical power circuit failure. Electrical elements in the control system energize to cause opening of the relief valve.

7.4.3.3.2 ADS Initiating Signals and Logic

The following initiation signals are used for the ADS:

- RPV water levels 1 and 3, high drywell pressure, and CS and/or RHR pump discharge pressure permissive signal, or

- RPV water level 1 sustained for a period of ~ 13 min, RPV water level 3, and CS and/or RHR pump discharge pressure permissive signal.

- Both ADS inhibit switches on the main control room panel must be in the "normal" position to allow initiation due to the above conditions.

These initiation signals must be present to cause the relief valves to open. RPV water level 1 indicates that the fuel is in danger of becoming overheated. This low water level would normally not occur unless the HPCI system failed. Primary containment high pressure indicates that a breach in the nuclear system process barrier has occurred inside the drywell.

After receipt of the initiation signals and after a delay provided by timers, the solenoid-operated pilot air valve is energized, provided that at least one LPCI or CS pump discharge pressure permissive signal is available, allowing pneumatic pressure from the accumulator to act on the piston actuator. The piston actuator is an integral part of the relief valve and acts to hold the relief valve open. Lights in the MCR inform the plant operator whenever the solenoid-operated pilot valve is energized, indicating that the relief valve has been commanded to open.

A two-position switch is provided in the MCR for the control of the relief valves. The two positions are open and auto. In the open position, the switch energizes the solenoid-operated pilot valve, which allows pneumatic pressure to be applied to the piston actuator of the relief valve. This allows the plant operator to take action independent of the automatic system. The relief valves can be manually opened to provide a controlled nuclear system cooldown under conditions where the normal heat sink is not available. Two separate types of timers are provided for each logic trip system. The first timer is initiated when an RPV water level 1 signal is received. The timer times out after a period of ~ 13 min. If an RPV water level 1 signal is still present, the timer output contributes to ADS initiation. Drywell high-pressure signals are bypassed and not required for ADS actuation under these circumstances. The second timer provides an approximate 130-s time delay in ADS logic initiation.

Reset push buttons are provided for each timer and the drywell high-pressure signals. The delay timers are recycled when their respective push buttons are pressed. Therefore, the operator may delay ADS initiation by recycling the 130-s timer in each logic system if plant conditions are deemed appropriate. Both 130-s timers must be reset to prevent auto blowdown.

Two manual keylocked ADS inhibit switches in the main control room are also used to prevent ADS initiation during an anticipated transient without scram (ATWS) event. By inhibiting ADS, the ATWS event can be mitigated because the reactor water level can be lowered to enhance the standby liquid control system (SLCS) effectiveness in shutting down the reactor.

The logic scheme used for initiating the system is shown in figure 7.4-2 and is a single trip system containing two logics. Each logic can initiate automatic depressurization. The trip system is powered by reliable dc buses. Instrument specifications and settings are listed in table 7.4-2. Two pressure transmitters are provided at the discharge of each CS and LPCI pump. Cables are routed from these transmitters to trip units in the MCR which are used to provide discharge pressure permissive signals. This instrumentation is part of the ATTS, which is discussed in section 7.18.

The RPV water level 1 initiation setting for the ADS is selected to open the relief valves to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the CS system and/or LPCI, following a LOCA in which the other makeup systems (RCIC system, HPCI system) fail to maintain vessel water level. The primary containment high-pressure setting is selected to be as low as possible without inducing spurious initiation of the ADS. The second RPV water level 3 initiation setting is selected to confirm that water level in the vessel is in fact low, thus providing protection against inadvertent depressurization in the event of an instrument line (water level) failure. Such a failure could produce a simultaneous high drywell pressure.

7.4.3.3.3 ADS Initiating Instrumentation

The pressure and level transmitters/trip units used to initiate the ADS are common to each relief valve control circuitry. RPV water level 1 is detected by four level transmitters that measure differential pressure. Cables are routed from these transmitters to trip units located in the MCR. Primary containment high pressure is detected by four pressure transmitters. Cables are routed from these transmitters to trip units located in the MCR. There are two additional RPV water level 3 transmitters/trip units which perform a permissive function for ADS initiation. These two level transmitters/trip units are activated at a higher level than the other four transmitter/trip units. As shown in figure 7.4-2, a minimum of three water level signals, two high drywell pressure signals, and two pump discharge pressure permissive signals are required to actuate each of the two logic circuits. However, if high drywell pressure signals are not present, they may be automatically bypassed, provided that a sustained water level 1 signal is present for ~ 13 min. This bypass function is controlled by two 13-min timers contained within each logic circuit. Either of the two logic circuits can initiate the ADS. The primary containment high-pressure signals are arranged to seal in within the control circuitry and must be manually reset. Reset closes all of the ADS valves if any one of the initiating signals has cleared. The 130-s delay time setting of the timers in the logic is chosen to be long enough so that the HPCI system has time to start, yet not so long that the CS system and LPCI are unable to adequately cool the fuel if the HPCI system fails to start. An alarm in the MCR is annunciated every time the timers are timing. Resetting the ADS logic in the presence of tripped initiating signals recycles the timers. The high drywell pressure bypass (13-min) timers must be manually reset when their initiating signals have cleared.

The requirement that at least one LPCI or CS pump discharge pressure permissive signal be available before automatic depressurization starts ensures that cooling is available to the core after the reactor system pressure is lowered. The pump discharge pressure setting used as a permissive for depressurization is selected to ensure that at least one of the four LPCI pumps or one of the CS pumps has received electrical power, has started, and is capable of delivering water into the vessel. The setting is high enough to ensure that the pump delivers near rated flow without being so low as to provide an erroneous signal indicating that the pump is actually running.

The water level and pressure instrumentation mentioned above is part of the ATTS, which is discussed in section 7.18.

Both manual keylocked ADS inhibit switches must be in the "inhibit" position to operationally prevent ADS initiation. An alarm in the main control room annunciates when one or both of these switches are in the "inhibit" position. A white light above each switch also indicates when that switch is in the "inhibit" position. The combination of keylocks, alarm, and indicating lights provide assurance that ADS will not be initiated unless the operator deliberately elects to do so. The alarm also serves to tell the operators that ADS initiation logic is susceptible to single failure when only one switch is in the "inhibit" position.

7.4.3.3.4 ADS Alarms

Safety relief valves position indication is provided by three indirect methods:

- Monitoring downstream pressure.
- Monitoring downstream temperature.
- Control switch contacts.

Pressure monitoring is accomplished by the use of two redundant pressure switches located in each safety relief valve discharge line (SRVDL). These switches are arranged in two groups. The first group consists of 11 pressure switches which operate control room relays powered from the Class 1E, 125 V-dc Division II power supply. The second group consists of 11 pressure switches which operate control room relays powered from the Class 1E, 125 V-dc Division I power supply. The relays powered from Division II provide signals to the plant annunciation system, the plant computer system, and the low-low set (LLS) relief logic system. The relays powered from Division I provide signals to LLS. These two groups have physical separation, and cables are routed through the respective divisional raceway.

The SRV pressure switch is tested during a shutdown once per operating cycle.

Temperature monitoring on each SRV is by copper constantan thermocouple connected to a common temperature recorder in the MCR. Power for this recorder is fed from the emergency 120 V-ac instrument bus, Division II. Position lights operated by the manual control switch of each valve are also provided. When the temperature in any SRVDL exceeds a preset value, an alarm is sounded in the MCR. The alarm setting is selected far enough above normal rated power temperatures to avoid spurious alarms yet low enough to give early indication of relief valve leakage.

Also, an alarm in the main control room annunciates when one or both of the manual keylocked ADS inhibit switches are in the "inhibit" position.

7.4.3.3.5 ADS Environmental Considerations

The signal cables, solenoid valves, and relief valve operators are items of the control and instrumentation equipment of the ADS that are located inside the primary containment and must remain functional in the environment resulting from a LOCA. These items are selected with capabilities that permit proper operation in the most severe environment resulting from a design basis LOCA. Gamma and neutron radiation are also considered in the selection of these items. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate.

Air actuator diaphragms are constructed of a silicone rubber coating applied to a reinforcing fabric such as nylon or nylon related polymers. The pressure rating is ≥ 150 psig, and the operating pressure is ≤ 110 psig. Published data indicate that a beginning of moderate damage will occur after exposure to 8 x 10^6 R which is equivalent to ~ 10 years or greater of normal operation.

Table 7.4-5 provides normal and emergency operating requirements.

It is recommended that each valve be removed at every other fueling outage for examination, test, and performance verification as a means of verifying diaphragm integrity. No qualification tests have been performed on the diaphragms; the manufacturers recommended continuous maximum operating temperature is in excess of the maximum environmental (emergency) temperature.

7.4.3.4 CS System Control and Instrumentation

7.4.3.4.1 Identification and Physical Arrangement

The CS system consists of two independent spray loops as illustrated on drawing no. H-16331. Each loop is capable of supplying sufficient cooling water to the reactor vessel to adequately cool the core following a design basis LOCA. The two spray loops are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes an ac motor-driven pump, appropriate valves, and the piping to route water from the suppression pool to the reactor vessel. The controls and instrumentation for the CS system includes the sensors, relays, wiring, and valve-operating mechanisms used to start, operate, and test the system. Except for the inboard check valve and associated 1-in. bypass valve in each spray loop, which are inside the primary containment, the sensors and valve closing mechanisms for the CS system are located in the reactor building. Cables from the sensors are routed to the MCR where the control circuitry is assembled in electrical panels. Each CS pump is powered from a different ac bus which is capable of receiving standby power. The power supply for automatic valves in each loop is the same as that used for the CS pump in that loop logic. Control power for each of the CS loops comes from separate dc buses.

7.4.3.4.2 CS System Initiating Signals and Logic

The control scheme for the CS system is illustrated on drawing nos. H-19944 through H-19946. Trip settings are given in table 7.4-3. The overall operation of the system following the receipt of an initiating signal is as follows:

A. Test bypass valves are closed and interlocked to prevent opening.

B. If normal ac power is available, the CS pumps in both spray loops start immediately.

C. If normal ac power is not available, the CS pumps in both spray loops start immediately after standby power becomes available for loading.

D. When reactor vessel pressure drops to a preselected value, valves open in the pump discharge lines allowing water to be sprayed over the core.

E. When pump discharge flow is indicated, the pump low-flow bypass valves shut, directing full flow into the reactor vessel.

Two initiating functions are used for the CS system: RPV water level 1 and primary containment (drywell) high pressure. Either initiation signal can start the system. Once initiated, reactor low-pressure signals are used as permissive signals to open the CS injection valves.

The logic scheme used for initiating each CS system loop is shown in figure 7.4-2 and is comprised of one trip system per loop which actuates upon receipt of the requisite low water level signals or upon receipt of the requisite high drywell pressure signals. Either trip system logic will initiate both CS loops associated with that trip system. The same sensors actuate the trip systems for loop A and loop B using isolated relay contacts for isolation between trip systems. The trip systems are powered by reliable independent dc buses.

RPV water level 1 indicates that the core is in danger of being overheated due to the loss of coolant. Drywell high pressure indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The RPV water level 1 and primary containment high-pressure settings and the instruments that provide the initiating signals are selected and arranged so as to assure adequate cooling for the design basis LOCA without inducing spurious system startups. The water level and pressure instrumentation mentioned above is part of the ATTS, which is discussed in section 7.18.

7.4.3.4.3 CS System Pump Control

The control arrangements for the CS pumps are shown on drawing no. H-19944. The circuitry provides for detection of normal power available so that both pumps are automatically started. Each pump can be manually controlled by a control room remote switch, or by the automatic initiation control system. A pressure transducer on the discharge line from each of the CS pumps provides a signal in the control room to indicate the successful startup of the pumps. If a

CS initiation signal is received when normal ac power is not available, both CS pumps start immediately after ac power is available for loading. (See table 8.4-1.) The CS pump motors are provided with overload protection. Overload relays are applied so as to maintain power as long as possible without immediate damage to the motors or emergency power system.

Flow-measuring instrumentation is connected in each of the CS pump discharge lines. The instrumentation provides flow indication in the MCR.

7.4.3.4.4 CS System Valve Control

Except where specified otherwise, the remainder of the description of the CS system refers to one spray loop. The second CS loop is identical. The control arrangements for the various automatic valves in the CS system are indicated on drawing nos. H-19944 through H-19946. All motor-operated valves are equipped with limit and torque switches to turn off the valve motor when the valve reaches the limits of movement and provide control room indication of valve position. In the opening circuit of motor-operated valves, the torque switch is bypassed. Each automatic valve can be operated from the MCR. Valve motors that are part of the core spray system have the control contact of the thermal overload protection relay continuously bypassed during normal plant operation. These valves also have thermal overload alarms to indicate an abnormal operating condition.

Upon receipt of an initiation signal, the test bypass valve is interlocked shut. The CS pump discharge valves are automatically opened when RPV pressure drops to a preselected value; the setting is selected low enough so that the low-pressure portions of the CS system are not overpressurized, yet high enough to open the valves in time to provide adequate cooling for the fuel. Four pressure transmitter/trip units are used to monitor RPV pressure. One-out-of-two taken-twice logic initiates opening of the discharge valves. The full-stroke operating times of the motor-operated valves are selected to be rapid enough to assure proper delivery of water to the reactor vessel in a design basis accident. The full-stroke design operating times are as follows:

- Test bypass valve 54 s
- Pump discharge valves 10 s[a]

A flow switch on the discharge of each set of pumps provides a signal to operate the minimum flow bypass line valve for each pump set. When the flow reaches the value required to prevent pump overheating, the valves close directing all flow into the sparger.

a. The LOCA analyses support a pump discharge valve opening time of 20 s for GE14 fuel and 30 s for GNF2 fuel.

7.4.3.4.5 CS System Alarms and Indications

CS system pressure between the two pump discharge valves is monitored by a pressure switch to permit detection of leakage from the nuclear system into the CS system outside the primary containment. A detection system is also provided to continuously confirm the integrity of the CS piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the CS sparger pipe just outside the reactor vessel. If the CS sparger piping is sound, this pressure difference will be the pressure drop across the core resulting from interchannel leakage. If integrity is lost, this pressure drop will include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the MCR. Pressure in each CS pump suction and discharge line is monitored by a pressure indicator which is locally mounted to permit determination of suction head and pump performance.

7.4.3.4.6 CS System Environmental Considerations

There are no control and instrumentation components for the CS system that are located inside the primary containment that must operate in the environment resulting from a LOCA. All components of the CS system that are required for system operation are outside the drywell and are selected in consideration of the normal and accident environments in which they must operate.

7.4.3.5 <u>LPCI Control and Instrumentation</u>

7.4.3.5.1 Identification and Physical Arrangement

LPCI is an operating mode of the RHR system that uses pumps and piping that are parts of the RHR system. Because LPCI is designed to provide cooling water to the reactor vessel following the design basis LOCA, the controls and instrumentation for it are discussed here. Section 4.8, RHR System, describes the RHR system in detail. Drawing nos. H-16329 and H-16330 show the entire RHR system, including the equipment used for LPCI operation. The following list of equipment itemizes essential components for which control or instrumentation is required:

- Four RHR system pumps.
- Pump suction valves.
- LPCI to recirculation loop injection valves.

The instrumentation for LPCI operation provides inputs to the control circuitry for other valves in the RHR system. This is necessary to ensure that the water pumped from the suppression chamber by the pumps is routed directly to a reactor recirculation loop. These interlocking features are described in this section. The actions of the reactor recirculation loop valves are described in this section because these actions are accomplished to facilitate LPCI operation.

LPCI operation uses two identical pump loops, each loop with two pumps in parallel. The two loops are arranged to discharge water into different reactor recirculation loops. No connection normally exists between the pump discharge lines of each loop. Drawing nos. H-16329 and H-16330 show the locations of instruments, control equipment, and LPCI components relative to the primary containment. Except for the LPCI check valves and the reactor recirculation loop pumps and valves, the components pertinent to LPCI operation are located outside the primary containment.

Motive power for each of the two injection valves used during LPCI operation comes from combination of HNP-2 600-V ac load centers backed by HNP-2 dedicated diesel generators and HNP-1 600-V ac MCC backed by swing diesel generator 1B (HNP-2-FSAR figure 8.3-8). Control power for the LPCI components comes from the dc buses. Redundant trip systems are powered from different dc buses.

LPCI is arranged for automatic operation and for remote manual operation from the MCR. The equipment provided for manual operation of the system allows the operator to take action independent of the automatic controls in the event of a LOCA.

7.4.3.5.2 LPCI Initiating Signals and Logic

The overall operating sequence for LPCI following the receipt of an initiation signal (drawing nos. H-19937 through H-1939) is as follows:

A. If normal ac power is available, all four pumps start simultaneously without delay. The pumps take suction from the suppression chamber. The valves in the suction paths from the suppression chamber are maintained open so that no automatic action is required to line up suction. These valves are provided with keylock switches.

B. If normal ac power is not available, one pump starts with no delay as soon as the standby power source is available for loading. The other three pumps start after a 12-s delay.

C. When the reactor pressure decreases to an appropriate setting, both recirculation loop discharge valves are signaled to close, and the recirculation pumps are tripped.

D. Other RHR system valves are automatically closed so that the water pumped from the suppression chamber is routed properly.

E. The RHR service water pumps automatically stop (if running) because they are not needed for LPCI operation.

F. When nuclear system pressure has dropped to a value at which the main system pumps are capable of injecting water into the recirculating loops, the LPCI valves automatically open to both loops.

G. After the LPCI startup sequence is complete, flow commences in both loops.

H. LPCI then delivers water to the reactor vessel via the recirculation loop to provide core cooling.

In the descriptions of LPCI controls and instrumentation that follow, drawing nos. H-16329 and H-16330 can be used to determine the physical locations of sensors, and drawing nos. H-19937 through H-19943 can be used to determine the functional use of each sensor in the control circuitry for the various LPCI components. Instrument characteristics and settings are given in table 7.4-4.

Two automatic initiation functions are provided for the LPCI: RPV water level 1 and primary containment (drywell) high pressure. Either initiation signal can start the system. Once initiated, reactor low-pressure signals are used to open the LPCI injection valves. RPV water level 1 indicates that the fuel is in danger of being overheated because of an insufficient coolant inventory. Primary containment high pressure is indicative of a break of the nuclear system process barrier inside the drywell.

The logic scheme used for initiating LPCI is shown in figure 7.4-2. The accident initiation signals direct both LPCI injection valves to open upon detection of accident conditions. The logic for one of the two identical initiation trip systems is shown on drawing nos. H-19937 and H-19938. Either of the two initiation trip system logics can indicate LPCI. The trip systems are powered by reliable, independent, dc buses. The instruments used to detect RPV water level 1 and primary containment high pressure are the same ones used to indicate the other ECCS subsystems. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset. The seal-in feature is shown on drawing no. H-19937. The water level instrumentation mentioned above is part of the ATTS, which is discussed in section 7.18.

7.4.3.5.3 LPCI Pump Control

The functional control arrangement for the pumps is shown on drawing no. H-19937. Once an initiation signal is received, the startup sequence of the pumps depends on the availability of power. If normal ac power is available, four pumps automatically start without delay. If normal ac power is not available, one pump starts without delay as soon as power becomes available from the standby sources. The other three pumps start after a 12-s delay. The time delays are indicated in the loading sequences provided in chapter 8 (table 8.4-1).

The timers provided in the LPCI circuitry for the main system pumps, as well as those used for the LPCI valves, are capable of adjustment over a range of 1.5 times the design setting listed in table 7.4-4.

Local pressure indicators and pressure switches that initiate alarms in the MCR are installed in the pump discharge lines upstream of the pump discharge check valves and provide indication of proper pump operation following an initiation signal. Low pressure in a pump discharge line indicates pump failure. The locations of the pressure indicators relative to the discharge check valves prevent the discharge pressure from an operating pump from concealing a pump failure.

To prevent pump damage due to overheating at no flow, the control circuitry prevents a pump from starting unless a suction path is lined up. Limit switches on suction valves provide indications that a suction lineup is in effect. If suction valves change from their fully open position during main system pump operation, the limit switches trip the pump power supply breaker open.

The pump motors are provided with overload protection. The overload relays are applied so as to maintain power on the motor as long as possible without harm to the motor or immediate damage to the standby power system.

The reactor recirculation pumps are tripped automatically upon a LOCA. The recirculation pump trip is part of the pump protection instrumentation. The pump trip signal is generated by closure of the suction or discharge isolation valves to a position < 90% open. If the pump were not tripped by this signal, overheating and possible motor damage might result from continued operation.

The maximum pressure differential that could exist across the isolation valves (without pump trip) would occur across the discharge valve and would be less than the pump zero-flow head which is ~ 225 psi. The discharge valve design specification requires closure capability with a 200-psi differential; this capability will likely be exceeded due to normal design margins incorporated by the valve vendors. The suction side valves pressure differential would be much less than the design specification closure capability of 50-psi differential.

If the recirculation pumps are running, they are automatically tripped at RPV water level 2. This level is higher than that at which LPCI is placed in operation (RPV water level 1). When a recirculation pump trip signal is initiated, the power supply breaker for the drive motors for the recirculation pump generators is tripped open and the motor-generator variable speed couplings remain as is. A failure-to-scram recirculation pump trip is implemented at Plant Hatch.

7.4.3.5.4 LPCI Valve Control

The automatic valves controlled by the LPCI control circuitry are equipped with appropriate limit and torque switches which turn off the valve operating mechanisms whenever the valves reach the limit of travel. Seal-in and interlock features are provided to prevent improper valve positioning during automatic LPCI operation. The operating mechanisms for the valves are selected so that the LPCI operation is in time for the system to fulfill its objective of providing adequate core cooling following a design basis LOCA. The time required for the valves pertinent to LPCI operation to travel from the fully closed to the fully open positions, or vice versa, is as follows:

- LPCI valves 51 s[b]

- Reactor recirculation loop valves 41 s[b]

The pump suction valves to the suppression pool are normally open. Two separate operator actions are required in the MCR to shut these valves. Upon receipt of a LPCI initiation signal, certain reactor shutdown cooling system valves and the RHR system test line valves automatically close, if open. By closing these valves, the pump discharge is properly routed. Also included in this set of valves are the valves which, if not closed, would permit the pumps to take a suction from the reactor recirculation loops, a lineup that is used during normal shutdown cooling system operation. Valve motors that are part of LPCI have the control contact of the thermal overload protection relay continuously bypassed during normal plant operation.

LPCI is designed for automatic operation following a break in one of the reactor recirculating loops. The accident initiation signal opens the injection valves to both recirculation loops and closes the recirculation pump discharge valves in both recirculation loops. The control scheme for the LPCI to recirculation loop injection valves is shown on drawing no. H-19915.

Upon receipt of either an RPV water level 1 or high drywell pressure signal, both separately motor-powered LPCI injection valves are directed to open. Redundant wiring and relays exist to attain additional single-failure probability. The discharge valves of the recirculation loop will begin closing upon receipt of a permissive signal. The sensor and permissive circuitry are designed to satisfy all requirements for engineered safeguards control systems.

After the LPCI startup sequence is complete, flow commences in both loops. Depending on the break location, flow in the broken loop may not reach its expected value until the discharge valve has fully closed. Two LPCI pumps will discharge into each injection header. No cross-connection normally exists between the two loops.

A timer cancels the LPCI signals to the injection valves after a delay time long enough to permit satisfactory operation of LPCI. The cancellation of the signals allows the operator to divert the water for other post-accident purposes. Cancellation of the signals does not cause the injection valves to move.

The manual controls in the MCR allow the operator to open a LPCI valve only if either trip system pressure is low or the other injection valve in the same line is closed. These restrictions prevent overpressurization of low-pressure piping. The same pressure switch used for the automatic opening of the valves is used in the manual circuit. Limit switches on both injection valves for each LPCI loop provide the valve position signals required for injection valve manual operation at high nuclear system pressure. There are two motor control centers (MCCs) for the LPCI valves; one supplies power to the loop A LPCI valves, and the other supplies power to the

b. The LOCA analyses support a longer travel time for these valves. (See HNP-2-FSAR table 6.3-4.)

loop B LPCI valves. Power to the MCCs is supplied by a combination of HNP-2 600-V ac load centers backed by HNP-2 dedicated diesel generators and HNP-1 600-V-ac MCC backed by swing diesel generator 1B (HNP-2-FSAR figure 8.3-8).

To protect the pumps from overheating at low flowrates, a minimum flow bypass line, which routes water from the pump discharge to the suppression chamber, is provided for each pair of pumps. A single motor-operated valve controls the condition of each bypass line. The minimum flow bypass valve automatically opens upon sensing low flow in the discharge lines from both pumps of the associated pump pair. The valve automatically closes whenever the flow from either of the associated main system pumps is above the low-flow setting. Two differential pressure transmitters are used to monitor flow in the common discharge line from each pair of pumps. One transmitter provides main control room indication and recording. Cables are routed from the other transmitter to a trip unit located in the MCR. The trip unit provides the signal for opening the minimum flow bypass valve. The trip unit and its associated transmitter are part of ATTS discussed in section 7.18.

Drawing no. H-19915 shows the control arrangement for the recirculation loop valves. The recirculation pump discharge valves in both recirculation loops automatically close upon the receipt of a permissive signal. Valve closure is delayed until RPV has decreased to the value listed in HNP-2-FSAR table 6.3-4.

The manual control circuitry for the recirculation loop valves is interlocked to prevent valve opening whenever a LPCI initiation signal is present.

The valves that divert water for containment spray are signaled closed on receipt of a LPCI initiation signal. These valves cannot be opened by manual action unless the LPCI initiation signal is bypassed by a manually operated switch located in the MCR, and the RPV water level equivalent to two-thirds core height, which indicates that the pumps are not needed for the LPCI function. Two differential pressure transmitters/trip units are used to monitor the water level inside the core shroud. Each is separately piped to the RPV.

In addition to the switch discussed above, a keylock switch located in the MCR allows manual override of the two-thirds core height and LPCI initiation signal permissives for the containment spray valves.

Sufficient temperature, flow, pressure, and valve position indications are available in the MCR for the plant operator to accurately assess the LPCI operation. Valves have indications of full-open and full-closed positions. Pumps have indications for pump running and pump stopped. Alarm and indication devices are shown on drawing nos. H-16329 and H-16330.

7.4.3.5.5 LPCI Environmental Considerations

The only control components pertinent to LPCI operation that are located inside the primary containment that must remain functional in the environment resulting from a LOCA are the cables and valve closing mechanisms for the recirculation loop isolation valves. The cables and valve operators are selected with environmental capabilities that assure valve closure under the environmental conditions resulting from a design basis LOCA. Gamma and neutron radiation is also considered in the selection of this equipment. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate.

7.4.4 SAFETY EVALUATION

In chapter 6 and HNP-2-FSAR chapter 15, Safety Analysis, the individual and combined capabilities of the ECCS are evaluated. The control equipment characteristics and trip settings described in this section were considered in the analysis of ECCS performance. For the entire range of nuclear process system break sizes, the cooling systems are effective both in preventing excessive fuel-cladding temperature and in preventing more than a small fraction of the reactor core from reaching the temperature at which a gross release of fission products can occur. This conclusion is valid even with significant failures in individual cooling systems because of the overlapping capabilities of the ECCS subsystem.

The ECCS instrumentation responds to the potential inadequacy of core cooling regardless of the location of a breach in the nuclear system process barrier. The RPV water level 1 initiating function (which alone can actuate LPCI and CS) and the water level 2 initiating function (which alone can actuate HPCI) meet this safety design basis, because a breach in the nuclear system process barrier inside or outside the primary containment is sensed by the low water level detectors. Because of the isolation responses of the primary containment and reactor vessel isolation control system to a breach of the nuclear system outside the primary containment, the use of the RPV water levels 1 and 2 signals as the only standby cooling system initiating function that is completely independent of breach location is satisfactory. The other major initiating function, primary containment high pressure, is provided because the primary containment and reactor vessel isolation control system may not be able to isolate all nuclear system breaches inside the primary containment. The primary containment high-pressure initiating signal for the ECCS provides a second reliable method for sensing coolant losses that cannot necessarily be stopped by isolation valve action. This second initiating function is independent of the physical location of the breach within the drywell. The method used to initiate the ADS, which employs RPV water levels 1 and 3 and primary containment high pressure in coincidence requires that the nuclear system breach be inside the drywell because of the required primary containment high-pressure signal. This control arrangement is satisfactory in view of the automatic isolation of the reactor vessel by the primary containment and reactor vessel isolation control system for breaches outside the primary containment and because the ADS is required only if the HPCI system fails.

An evaluation of ECCS controls shows that no operator action beyond the capacity of the operator is required to initiate the correct responses for the CSCSs. The alarms and indications provided to the operator in the control room allow interpretation of any situation requiring ECCS operation and verify the response of each system. Manual controls are illustrated on functional control diagrams. The plant operator can manually initiate every essential ECCS operation.

The redundancy provided in the design of the ECCS control equipment is consistent with the redundancy of the cooling systems themselves. The arrangement of the initiating signals that come from common sensors for the ECCS is similar to that provided by the dual trip system arrangement of the reactor protection system (RPS). No failure of a single initiating sensor channel can prevent the start of the cooling systems. The numbers of control components provided in the design for individual cooling system components is consistent with the need for the controlled equipment. An evaluation of the control scheme for each ECCS component shows that no single control failure can prevent the combined cooling systems from providing the core with adequate cooling. In performing this evaluation, the redundancy of components and cooling systems was considered. The functional control diagrams provided with the descriptions of cooling systems controls were used in assessing the functional effects of instrumentation failures. In the course of the evaluation, protection devices which can interrupt the planned operation of cooling system components were investigated for the results of their normal protective action as well as maloperation on core cooling effectiveness. The only protection devices that can act to interrupt planned ECCS operation are those that must act to prevent complete failure of the component or system. Examples of such devices are the HPCI system turbine overspeed trip, HPCI system steam line break isolation trip, pump trips on low suction pressure, and automatically controlled minimum flow bypass valves for pumps. In every case, the action of a protective device cannot prevent other redundant cooling systems from providing adequate cooling to the core.

The locations of controls where operation of ECCS components can be adjusted or interrupted have been surveyed. Controls are located in areas under the surveillance of operations personnel. Local control switches are of the keylock type, and MCR override of local switches is provided. Other controls are located in the MCR and are under the supervision of the plant operator.

The environmental capabilities of the ECCS instrumentation are discussed in the descriptions of the individual systems. Components which are located inside the primary containment and are essential to ECCS performance are designed to operate in the environment resulting from a LOCA (radiation, pressure, temperature, and steam atmosphere).

Special consideration has been given to the performance of RPV water level and pressure sensors, temperature equalizing columns, and condensing chambers during rapid depressurization of the nuclear system. The discussion of this consideration is included in section 7.2 and is equally applicable to the ECCS instrumentation. The HNP-1 Technical Specifications give guidance and impose limitations regarding the interrelationship of the protective systems. For the RPS and engineered safety features (ESF) systems, the use of available manual bypasses will be limited by the Technical Specifications. Additionally, there is located in the control room, on the console front so as to be in clear view of the operator, a manually operated light display board to warn the operator of an ESF system that is inoperable because of previous failure, repair work in progress, or routine maintenance. The annunciator is a manual on-off type that is initiated by the operator or other qualified person when an ESF system is not in service. The board remains illuminated for as long as the system is inoperable. The systems which are displayed are:

- HPCI.
- ADS.

- CS I.
- CS II.
- LPCI I.
- LPCI II.
- Standby gas treatment system (SGTS) I.
- SGTS II.

7.4.5 INSPECTION AND TESTING

Components required for HPCI, LPCI, and CS are designed to allow functional testing during normal power operation. Overall testing of these systems is described in the chapter 6, Emergency Core Cooling System. During overall functional tests, the operability of the valves, pumps, turbines, and their control instrumentation can be checked. The relief valves are subjected to tests during shutdown periods.

Logic circuitry used in the ECCS controls can be individually checked by applying test or calibration signals to the sensors or to the trip units in the MCR and observing trip system responses. Valve and pump operation from manual switches verifies the ability of breakers and valve closing mechanisms to operate. The ECCS automatic control circuitry is arranged to restore each of the cooling systems to normal operation if a LOCA occurs during a test operation; however, certain tests, such as flow tests of the ECCS pumps, require manual override of the automatic circuitry; and following such tests, the system must be restored manually.

TABLE 7.4-1

HPCI SYSTEM INSTRUMENT INITIATION AND CONTROL SETTINGS

HPCI Function	Instrument	Initiation Settings
RPV water level high - level 8[d]	Differential pressure transmitter/trip unit	(a)
HPCI diaphragm turbine exhaust/ pressure - high	Pressure transmitter/trip unit	(a)
HPCI system pump suction pressure trip - low	Pressure transmitter/trip unit	(e)
RPV water level - low low, level 2[b][d]	Differential pressure transmitter/trip unit	(a)
Drywell pressure - high[b]	Pressure transmitter/trip unit	(a)
HPCI steam supply line pressure - low	Pressure transmitter/trip unit	(a)
CST level - low[c]	Level switch	(a)
HPCI turbine overspeed trip	Centrifugal device	(e)
Suppression pool water level - high	Differential pressure transmitter/trip unit	(a)
HPCI steam line flow - high	Differential pressure transmitter/trip unit	(a)
Turbine exhaust pressure - high	Pressure transmitter/trip unit	(e)
HPCI pump discharge flow - low	Differential pressure transmitter/trip unit	(a)

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. Incident detection circuitry instrumentation.
c. Referenced to CST bottom.
d. Referenced to instrument zero.
e. Allowable values are listed in HNP-1 Technical Requirements Manual. See HNP-1 Instrument Setpoint Index for actual setpoints.

TABLE 7.4-2

ADS INSTRUMENT TRIP SETTINGS

System Function	Instrument Type	Trip Settings
RPV water level - low low low (level 1)[b][c]	Differential pressure transmitter/trip unit	(a)
Drywell pressure - high[b]	Pressure transmitter/trip unit	(a)
Automatic depressurization time delay[b]	Timer	(a)
LPCI pump discharge pressure - high[b]	Pressure transmitter/trip unit	(a)
CS pump discharge pressure - high[b]	Pressure transmitter/trip unit	(a)
RPV water level - low (level 3)[c] (confirmed)	Differential pressure transmitter/trip unit	(a)
ADS drywell pressure bypass time delay	Timer	(a)

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. Incident detection circuitry instrumentation.
c. Referenced to instrument zero.

TABLE 7.4-3

CS SYSTEM INSTRUMENT TRIP SETTINGS

CS Function	Instrument Type	Trip Settings
RPV water level - low low low (level 1)[b][d]	Differential pressure transmitter/trip unit	(a)
Drywell pressure - high [b]	Pressure transmitter/trip unit	(a)
RPV pressure - low	Pressure transmitter/trip unit	(a)
CS sparger differential pressure - high	Differential pressure switch	≤ 3.1 psid[c]
CS Pump discharge flow - low	Differential pressure transmitter/trip unit	(a)

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. Incident detection circuitry instrumentation.
c. The trip setting is ≤ 3.1 psid greater (less negative) than the normal indicated ΔP at rated core power and flow.
d. Referenced to instrument zero.

TABLE 7.4-4

LPCI INSTRUMENT TRIP SETTINGS

LPCI Function	Instrument Type	Trip Settings
RPV water level - low low low (level 1) (LPCI pump start signal)[b][c]	Differential pressure transmitter/trip unit	(a)
Drywell pressure - high (LPCI Initiation)[b]	Pressure transmitter/trip unit	(a)
RPV water level (level 0) (inside shroud) [c]	Differential pressure transmitter/trip unit	(a)
LPCI reactor vessel pressure - low	Pressure transmitter/trip unit	(a)
LPCI throttle valve permissive	Timer	(d)
LPCI pump flow - low	Differential pressure transmitter/trip unit	(a)
RPV permissive (recirculation valve closure)	Pressure transmitter/trip unit	(a)

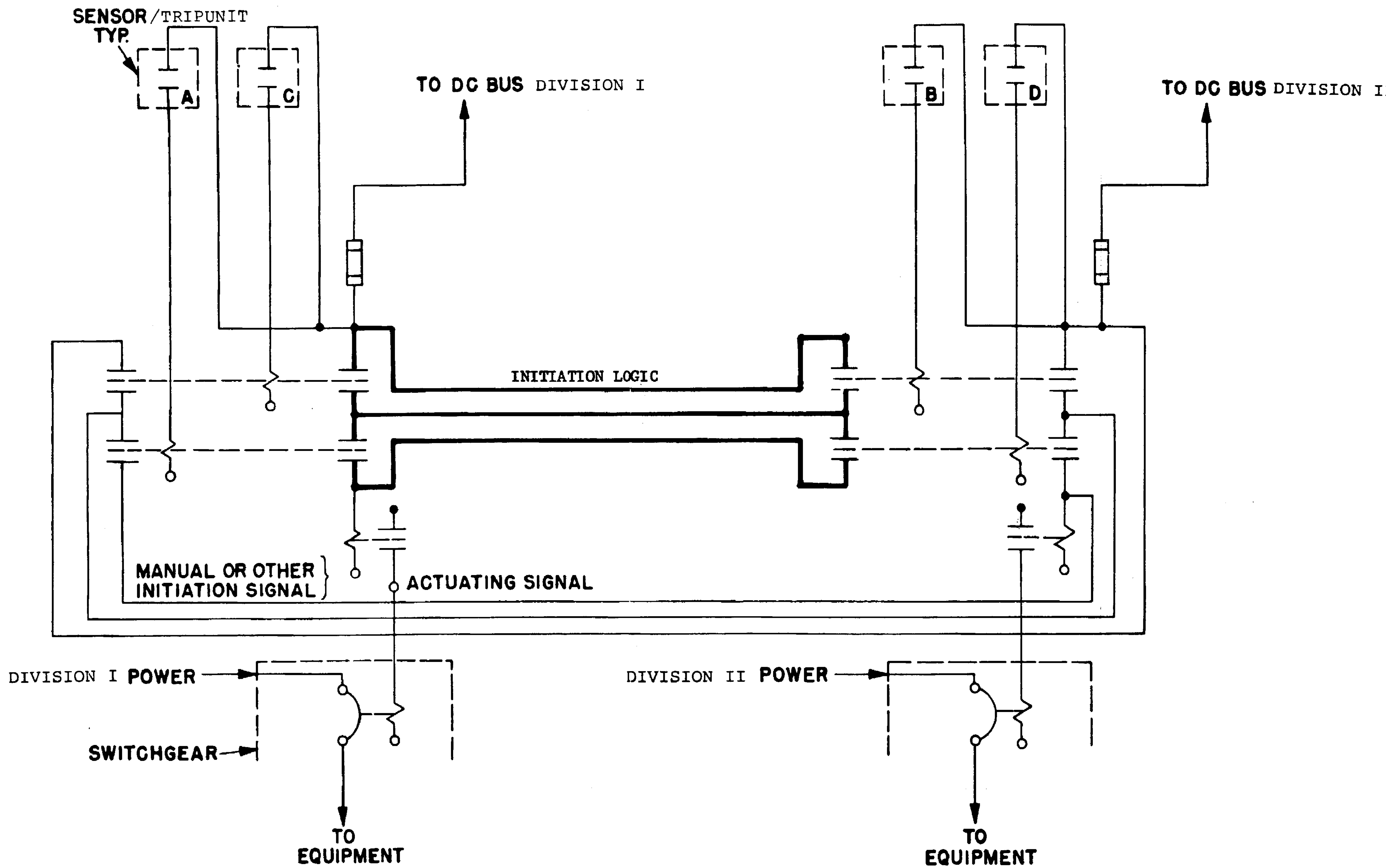
a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. Incident detection circuitry instrumentation. LPCI pump start sequence is shown on drawing no. H-19937.
c. Referenced to instrument zero.
d. See HNP-1 Instrument Setpoint Index for actual setpoints.

TABLE 7.4-5

OPERATING REQUIREMENTS FOR PRESSURE RELIEF VALVE AIR ACTUATOR DIAPHRAGMS

	Duration[a]					
	Normal	Emergency				
	Continuous	60s	3h	3h	18h	100 days
Temperature (°F)	150 (max)	340 (max)	340 (max)	320 (max)	250 (max)	200 (max)
Pressure (psig)	0-2	65 (max)	35 (max)	35 (max)	25 (max)	20 (max)
Relative humidity (%)	100	100	100	100	100	100
Gamma radiation (R/h)	65 (max)	65 (max)	65 (max)	65 (max)	65 (max)	65 (max)
Neutron and gamma radiation (R/h)	75 (max)	75 (max)	75 (max)	75 (max)	75 (max)	75 (max)

a. Total duration is the sum of the separate durations.



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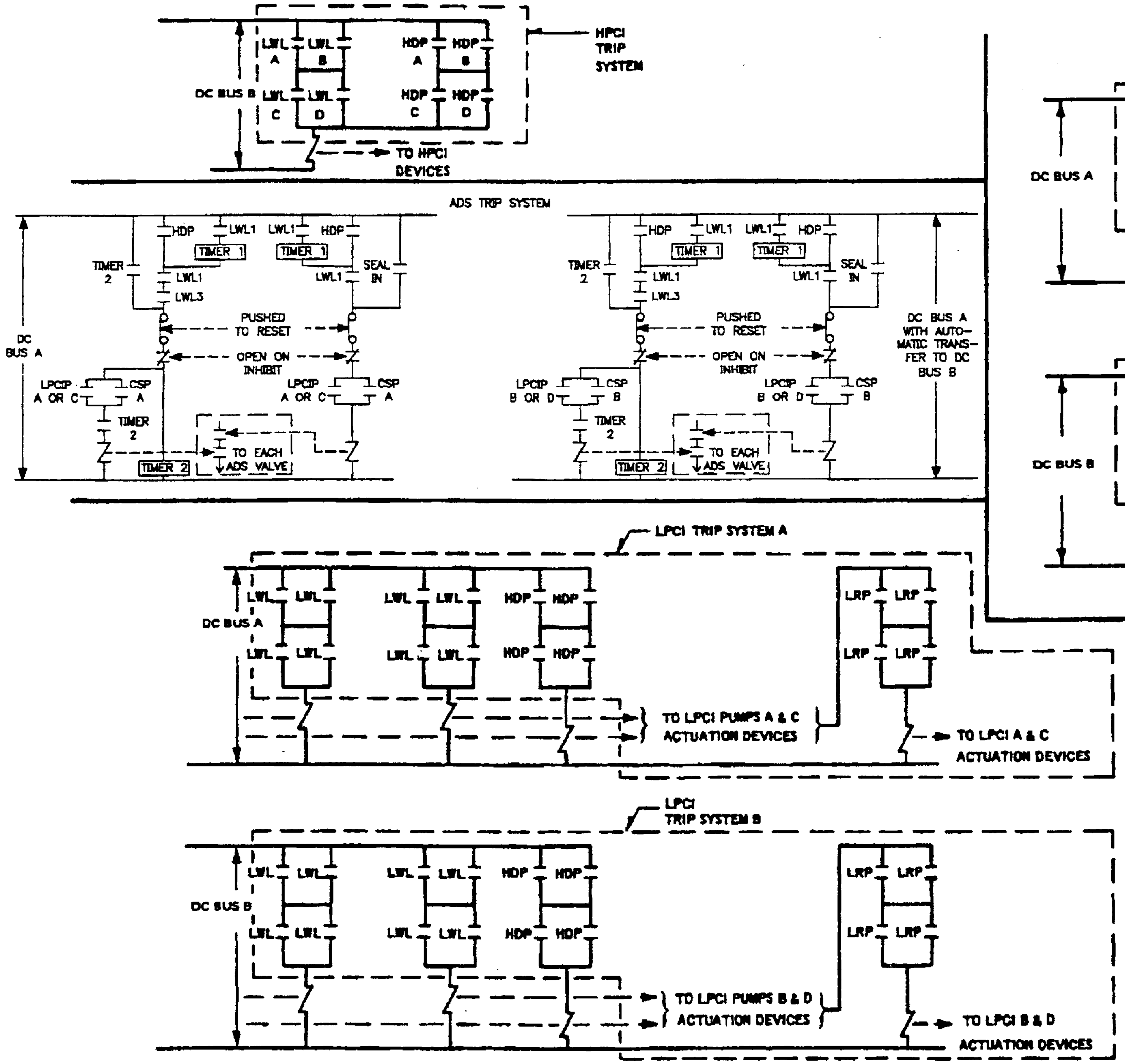
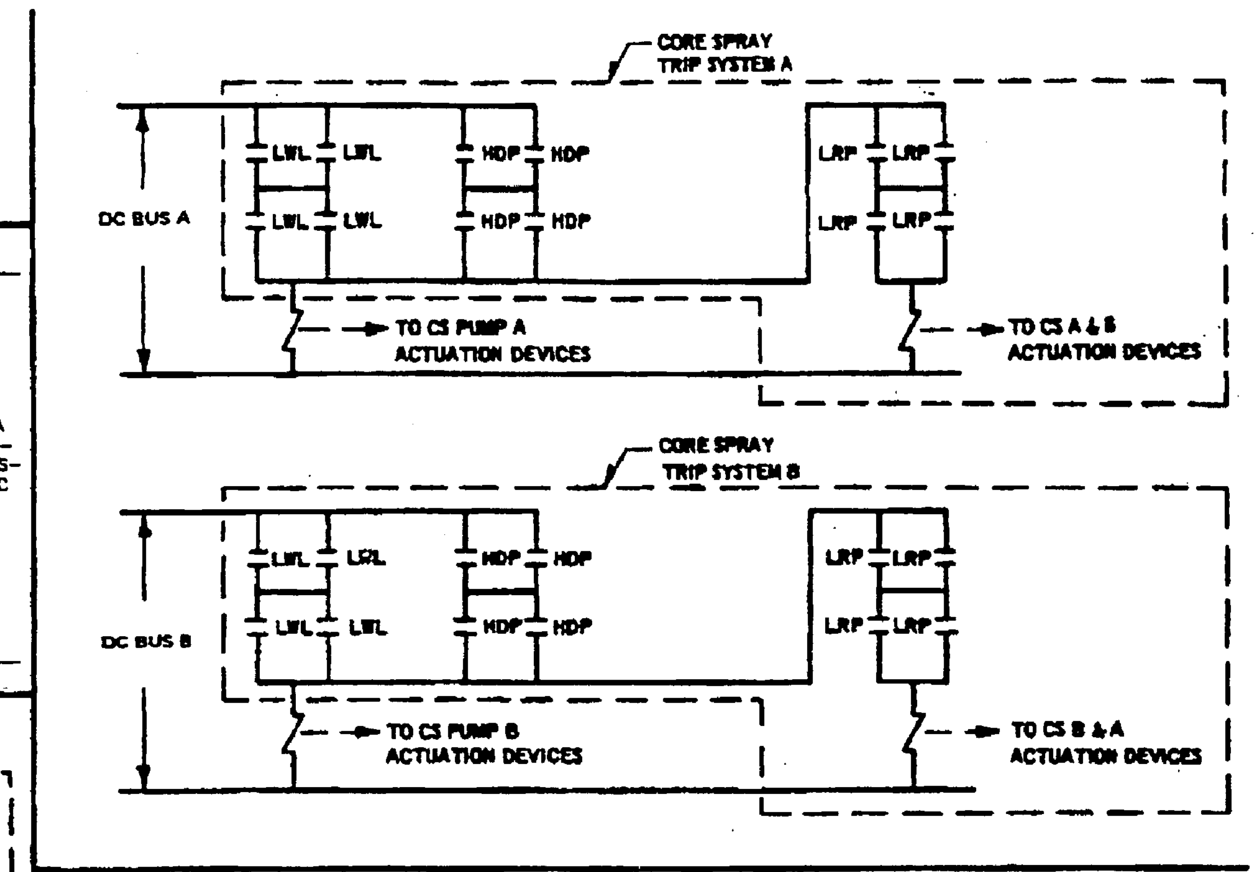
TYPICAL ECCS ACTUATION AND
INITIATION LOGIC

FIGURE 7.4-1





NOTES:

2. THIS FIGURE ILLUSTRATES THE ECCS ACTUATION LOGIC IN SIMPLIFIED FORM AND DEFINES TERMS USED IN SUBSECTION 7.A.

3. SWITCH IDENTIFICATION IN HPCI AND ADS IS TYPICAL OF ALL SYSTEMS SHOWN.

LEGEND:

LWL - LOW WATER LEVEL
HDP - HIGH DRYWELL PRESSURE
ADS - AUTOMATIC DEPRESSURIZATION SYSTEM
CSP - CORE SPRAY PUMP RUNNING
LPCIP - LPCI PUMP RUNNING
LRP - LOW REACTOR PRESSURE

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TYPICAL ECCS TRIP SYSTEM ACTUATION LOGIC

FIGURE 7.4-2

7.5 NEUTRON MONITORING SYSTEM (NMS)

7.5.1 SAFETY OBJECTIVE

The safety objective of the NMS is to detect excessive power generation and thermal-hydraulic instabilities in the core that threaten the overall integrity of the fuel barrier and provide signals to the reactor protection system (RPS) so that the release of radioactive materials from the fuel barrier is limited.

7.5.2 POWER GENERATION OBJECTIVE

The power generation objective of the NMS is to provide information for the efficient, expedient operation and control of the reactor. Two specific power generation objectives of the NMS are to detect conditions that could lead to local fuel damage and to provide signals that can be used to prevent such damage so that plant availability is not reduced.

7.5.3 IDENTIFICATION

The NMS consists of the following seven major systems:

- Source range monitor (SRM).
- Intermediate range monitor (IRM).
- Local power range monitor (LPRM).
- Average power range monitor (APRM).
- Rod block monitor (RBM).
- Traversing incore probe (TIP).
- Oscillation power range monitor (OPRM).

7.5.4 SOURCE RANGE MONITOR SUBSYSTEM

7.5.4.1 Power Generation Design Bases

A. Neutron sources (provided during startup) and neutron detectors, which together result in a signal count-to-noise count ratio of no < 2:1 and a count rate of no < 3 counts/s with all control rods fully inserted prior to initial power operation are provided. The ratio is measured in the field during startup testing and subsequently is that of (signal + noise)/noise. The minimum required value for this ratio is 3:1; however, in the literature, this ratio has often been referred to in error as the signal-to-noise ratio. Based on a (signal + noise)/noise ratio of 3:1, the correct signal-to-noise ratio is 2:1. Thus, no lowering of the true signal to noise ratio has been made; and the same criterion and test will continue to apply. The signal-to-noise ratio of 2:1 is a very conservative one, chosen to ensure an adequate neutron signal being present when the neutron level is low, and could possibly undergo a sudden increase. Experience with operating plants has consistently shown that a 1:1 ratio would be sufficient. During subsequent operations, these requirements are met before the reactivity of the core exceeds the reactivity which existed with all control rods fully inserted prior to initial power operation.

B. The SRM system is designed to indicate a measurable increase in output signal from at least 1 detecting channel before the indicated reactor period is < 20 s during the worst possible startup rod withdrawal conditions.

C. The SRM system is designed to indicate substantial increases in output signals with the maximum permitted number of SRM channels out of service during normal reactor startup operations.

D. The SRM system is designed so that SRM channels are on scale when the IRM subsystem first indicates neutron flux during a reactor startup.

E. The SRM system provides a measure of the time rate of change of the neutron flux (reactor period) for operational convenience.

F. The SRM system is capable of generating a trip signal to block control rod withdrawal if the count rate exceeds a preset value or falls below a preset limit (if the IRMs are not above the second range) or if certain electronic failures occur.

7.5.4.2 Description

7.5.4.2.1 Identification

The SRM system (drawing nos. H-16560 and H-16561) provides neutron flux information during reactor startup and low flux level operations. There are four SRM channels, each of which includes one detector that can be physically positioned in the core from the control room. The detectors are inserted into the core for a reactor startup and may be withdrawn if the indicated count rate is between preset limits or if the IRM is on the third range or above.

7.5.4.2.2 Power Supply

The power for the monitors is supplied from the 2 separate 24 V-dc buses, 2 monitors on 1 bus, and 2 monitors on the other.

7.5.4.2.3 Physical Arrangement

Each detector assembly consists of a miniature fission chamber operated in the pulse counting mode and attached to a low-loss quartz fiber insulated transmission cable (drawing no. S-15591). The sensitivity of the detector is 1.2×10^{-3} Hz/nv nominal, 5.0×10^{-4} Hz/nv minimum, and 2.5×10^{-3} Hz/nv maximum. The detector cable is connected underneath the reactor vessel to the triple-shielded coaxial cable. This shielded cable carries the pulses formed to a pulse current preamplifier located outside the primary containment.

The detector and cable are located inside the reactor vessel in a dry tube sealed against reactor vessel pressure. A remote-controlled detector drive system can move the detector along the length of the dry tube allowing vertical positioning of the chamber at any point from 18 in. above the reactor (fuel) centerline to 2.5 ft below the reactor fuel region (figure 7.5-1). The detector can be stopped at any location between the limits of travel, but only the end points of travel are indicated. When a detector arrives at a travel end point, the detector motion is automatically stopped.

The electronics for the SRMs, their trips, and their bypasses are all located in one four-bay cabinet. Source range signal-conditioning equipment is designed so that it may also be used for initial fuel loading.

7.5.4.2.4 Signal Conditioning

A current pulse preamplifier provides amplification and impedance matching to allow signal transmission to the signal-conditioning electronics (figure 7.5-2).

The signal-conditioning equipment is designed to:

- Receive a series of input current pulses.
- Convert the current pulse series to analog dc currents corresponding to logarithm of the count rate (LCR).
- Derive the period.
- Display the outputs on front panel meters.
- Provide outputs for remote meters and recorders.

The LCR meter displays the rate of the occurrence of the input current pulses, and the period meter displays the time in seconds for the count rate to change by a factor of 2.72. In addition, the equipment contains integral test and calibration circuits, trip circuits, power supplies, and selector circuits.

A high-voltage power (HVPS) supply provides a polarizing potential for the fission counter detectors. The potential is introduced to the detector through a filter network to minimize noise coupling.

The pulses from the pulse preamplifier are of various heights. In general, the pulses produced by neutrons are larger than pulses due to gamma and noise. To count only neutrons, the pulse height discriminator is set to reject the small pulses and to accept only the large pulses, the threshold being adjustable. One output of the pulse height discriminator has two stable states represented by full voltage and zero voltage. Each time an input pulse exceeds the threshold, the output of the pulse height discriminator reverses state and holds that state until the next pulse causes another reversal. The pulse height discriminator provides the pulse train input required by the log integrator. The pulse height discriminator also has a scaler output which produces an output pulse for each input pulse crossing the threshold. The various signals are shown in the block diagram (figure 7.5-2) outlined by circles. At A, the current pulses are shown as four different amplitudes to illustrate the output of the fission chamber. At B, the absolute amplitudes are increased, but the relative amplitudes remain proportional. A dashed line representing the threshold level is indicated. At C, there is an output pulse for every input pulse exceeding the threshold. This illustrates the action of the discriminator. This pulse is shaped to be compatible with the scaler input requirements. At D, the pulse height discriminator produces an output to the log integrator.

The log integrator is a network arranged to synthesize the response, which is a logarithmic function of the counting rate. This log integrator has a time constant which varies with the counting rate. Thus, at low counting rates, the time constant is large to provide an adequate smoothing effect on the reading. At high counting rates, the time constant is small to provide for a faster overall response time.

The output of the log integrator is a current output requiring amplification. Operational amplifier No. 1 is used to convert the current output from the log integrator to the standard signal used to drive the meter, recorders, trip circuits, and the period amplifier. Operation amplifier No. 2 is a differentiator with a resistor feedback and a capacitor input. The gain of the amplifier is scaled to produce a full scale period reading of + 10 s.

Calibration features are included to enable the accuracy of all measuring circuits to be verified and the tip level of the trip circuits to be set and checked. A signal generator provides two discrete frequencies for use in verifying the calibration of the log integrator and provides an operational check on the pulse height discriminator.

7.5.4.2.5 Trip Functions

The trip outputs of the SRM system (drawing nos. H-19930 and H-19932) are all designed to operate in the fail-safe mode; the loss of power to the SRM system causes the associated trips to function. (See figure 7.5-4.)

The SRM system provides SRM upscale, downscale, detector improper position, and inoperative signals to the reactor manual control system (RMCS) to block rod withdrawal under certain conditions. Any one SRM channel can initiate a rod block. These rod blocking functions are discussed in section 7.7, Reactor Manual Control System. Appropriate lights and annunciators are actuated to indicate the existence of these same conditions (table 7.5-1). Any one, but only one, of the four SRM channels can be bypassed by the operation of a switch on the operator's console.

7.5.4.3 <u>Power Generation Evaluation</u>

Design calculations show that if the multiplication of one section of the core is increased to the extent necessary to put that section of the reactor on a 20-s period, the nearest SRM chamber shows an increase in count rate. In general, at least one detector indicates the change in multiplication. These calculations use the design source intensity and neutron diffusion through the surrounding subcritical core.

Normal startup procedures require specific rod withdrawal patterns that ensure that the withdrawn control rods are distributed about the core so that the multiplication in no one section of the core exceeds the average by a large amount. Hence, each SRM chamber can respond to some degree as the initial rod withdrawal is accomplished. Current design indicates that a scattered rod withdrawal of ~ 1/4 of all control rods is required to reach criticality.

Examination of the sensitivity of the SRM detectors (paragraph 7.5.4.2.3) and their operating ranges of 10^6 nv indicates that the IRMs are on scale before the SRM reaches full scale. (See figure 7.5-3.) Further overlap is provided by retraction of the SRM chambers to any position between full-in and full-out.

7.5.4.4 <u>Inspection and Testing</u>

Each SRM channel is tested and calibrated using the procedures in the SRM instruction manual. Inspection and testing are performed as required on the SRM detector drive mechanism; the mechanism can be checked for full insertion and retraction capability. The various combinations of SRM trips can be introduced to ensure the operability of the rod blocking functions.

7.5.5 INTERMEDIATE RANGE MONITOR SYSTEM

7.5.5.1 Safety Design Bases

A. The IRM system is capable of generating a trip signal that can be used to prevent fuel damage resulting from anticipated operational occurrences (AOOs) that occur while operating in the intermediate power range.

B. The independence and redundancy incorporated in the design of the IRMS are consistent with the safety design basis of the RPS.

7.5.5.2 Power Generation Design Bases

A. The IRM system is capable of generating a trip signal to block rod withdrawal if the IRM reading exceeds a preset value or if the IRM is not operating properly.

B. The IRM system is designed so that overlapping neutron flux indications exist with the SRM system and the power range neutron monitoring (PRNM) system.

7.5.5.3 Description

7.5.5.3.1 Identification

The IRM monitors neutron flux from the upper portion of the SRM range to the lower portion of the PRNM range. The IRM (drawing nos. H-16560 and H-16561) has eight IRM channels, each of which includes one detector that can be physically positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to RUN.

7.5.5.3.2 Power Supply

Power is supplied separately from two 24 V-dc sources. The supplies are split according to their use so that loss of a power supply will result in loss of power to the channels associated with only one trip system of the RPS. Conduits and physical separation isolate the power buses external to the IRM cabinet.

7.5.5.3.3 Physical Arrangement

Each detector assembly consists of a miniature fission chamber attached to a low-loss, quartz fiber-insulated transmission cable. When coupled to the signal-conditioning equipment, the detector produces an approximate 30% reading on the sensitive range with a neutron flux of 10^8 nv. The detector cable is connected underneath the reactor vessel to a triple-shielded cable which carries the pulses generated in the fission chamber through the primary containment to the preamplifier. The detector and cable are located in the drywell, are movable in the same manner as the SRM detectors, and use the same type of mechanical arrangement.[1]

7.5.5.3.4 Signal Conditioning

A voltage amplifier unit located outside the primary containment serves as a preamplifier. This unit is designed to:

- Accept superimposed current pulses from the fission chamber.
- Remove the dc component.
- Convert the current pulses to voltage pulses.
- Amplify the voltage pulses.
- Establish the bandpass characteristics for the system.
- Provide a low impedance output suitable for driving a terminated cable.

The gain of the low range of the preamplifier is fixed but the gain of the high range is variable over a limited range to permit tracking between low and high ranges.

The signal-conditioning equipment for each IRM channel contains:

- An input signal attenuator.
- Additional stages of amplification.
- An inverter.
- A mean square analog unit.
- A calibration and diode logic unit.
- A range switch.
- Power supplies.
- Trip circuits.
- Integral test and calibration circuits (figure 7.5-4).

The amplification and attenuation ratios of the IRM and preamplifier are selected by a remote range switch which provides 10 ranges of increasing attenuation (the first 6 called low range and the last 4 called high range) acting upon the signal from the fission chamber. The output current is proportional to the power contained in the pulses received from the fission chamber. This output signal, which is proportional to neutron flux at the detector, is amplified and supplied to a locally mounted meter and an indicator recorder on the main control board. The meter and indicator recorder have two linear scales on a single face. The appropriate range being used is indicated by the range switch position. There is a potentiometer in the amplifier with a gain effect of 1 to 1.85, which provides an adjustment $>$ 1 range position (an approximate factor of 3 in flux) in the output signal. The calibration and diode logic unit include a circuit to develop a triangular wave shape signal of adjustable amplitude to provide a means of full-scale calibration of the power meter. Calibration settings of 40 on a 0-40 scale and 125 on a 0-125 scale are possible.

The HVPS associated with IRM supplies the polarizing potential for the fission chamber detector through a filter network to minimize noise coupling.

7.5.5.3.5 Trip Functions

The IRM is divided into two groups of IRM channels arranged in the core as shown on drawing no. H-16560. IRM channels (A, C, E, and G) are associated with trip system A of the RPS. IRM channels B, D, F, and H are associated with trip system B. Two IRM channels and their trip auxiliaries from a group are installed in one bay of a cabinet; the other channels are installed in a separate bay of the cabinet. Full-length side covers on the cabinet bays isolate the cabinet bays. The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising IRM capability.

Each IRM channel includes four trip circuits as standard equipment. One trip circuit is used as an instrument troubletrip. It operates whenever the high voltage drops below a preset level, whenever one of the modules is not plugged in, or whenever the operate-calibrate switch is not in the operate position. Each of the other trip circuits can be chosen to operate whenever preset downscale or upscale levels are reached. A simplified circuit arrangement of the IRM trips is shown in figure 7.5-5.

The trip functions actuated by the IRM trips are indicated in table 7.5-2. The reactor mode switch determines whether IRM trips are effective in initiating a rod block and a reactor scram. (See drawing nos. H-24724 and H-24727.) Section 7.7, Reactor Manual Control System, describes the IRM rod block trips. With the reactor mode switch in REFUEL or STARTUP, an IRM upscale or inoperative trip signal actuates a NMS trip of the RPS. Only one IRM channel must trip to initiate a NMS trip of the associated trip system of the RPS.

7.5.5.4 Safety Evaluation

The safety evaluation in section 7.2, Reactor Protection System, evaluates the arrangement of redundant input signals to the RPS. The NMS trip input to the RPS and the trip channels used in actuating a NMS trip are of equivalent independence and redundancy to other RPS inputs.

The number and locations of the IRM detectors were analytically and experimentally determined to provide sufficient intermediate range flux level information under the worst permitted bypass or detector failure conditions. For verification of this, a range of rod withdrawal accidents was analyzed. The most severe case assumes that the reactor is just subcritical with one-fourth of the control rods, plus one more rod, removed in the normal operating sequence. This configuration is illustrated in figure 7.5-6. The error or malfunction is the removal of the control rod adjacent to the last rod withdrawn. The location of this rod was chosen to maximize the distance to the second nearest detector for each RPS trip system. It is assumed that the nearest detector in each RPS trip system is bypassed. A scram signal is initiated when one IRM detector in each RPS trip system reaches its scram trip level.

To assure that each IRM is on the correct range, a rod block is initiated any time the IRM is both downscale and not on the most sensitive (lowest) scale. A rod block is initiated if the IRM detectors are not fully inserted in the core and the reactor mode switch is not in the RUN position. The IRM scram trips are automatically bypassed when the reactor mode switch is in the RUN position and the APRMs are on scale. The IRM rod block trips are automatically bypassed when the reactor mode switch is in the RUN position.

The IRM detectors and electronics were tested under operating conditions and verified to have the operational characteristics given in the description and as such provide the level of precision and reliability required by the RPS safety design basis.

7.5.5.5 Power Generation Evaluation

The IRM system is the primary source of information on the approach of the reactor to the power range. Its linear, approximate half-decade steps, with the rod blocking features on both high-flux level and low-flux level, require that the operator keep all the IRMs on the correct range to increase core reactivity by rod motion. The SRM overlaps the IRM as shown in figure 7.5-3. The sensitivity of the IRM is such that it is on scale on the least sensitive (highest) range with the reactor power ~ 15%.

7.5.5.6 Inspection and Testing

Each IRM channel is tested and calibrated using the procedures in the IRM instruction manual. The IRM detector drive mechanisms and the IRM rod-blocking functions are checked in the same manner as for the SRM channels. Each of the various IRM channels can be checked to ensure that the IRM high-flux scram function is operable.

7.5.6 LOCAL POWER RANGE MONITOR SYSTEM

No safety design bases are specified for the LPRMs; however, since they form inputs to the APRM and OPRM systems, a minimum number of LPRMs must be operable for each APRM as defined in the APRM safety design bases, paragraph 7.5.7.1.

7.5.6.1 Power Generation Design Bases

A. The LPRMs provide signals proportional to the local neutron flux at various locations within the reactor core to the APRM and OPRM systems so that accurate measurements of average reactor power and core stability can be made.

B. The LPRMs supply signals to the RBM system so that measurement of changes in local relative neutron flux can be made during the movement of control rods.

C. The LPRM system is capable of alarming under conditions of high or low local neutron flux.

D. The LPRM system supplies signals proportional to the local neutron flux to the process computer to be used in power distribution calculations, local heat flux calculations, minimum critical power ratio (MCPR) calculations, and fuel burnup calculations.

E. The LPRM system supplies signals proportional to the local neutron flux to drive indication on operator display assemblies and auxiliary devices to be used for evaluating power distribution, local heat flux, MCPR, and fuel burnup rate.

7.5.6.2 Description

7.5.6.2.1 Identification

The LPRM system (drawing no. H-16561) consists of the fission chamber detectors, the signal-conditioning equipment, and trip functions. The LPRM signals are also used in the APRM system, OPRM system, the RBM system, and the process computer.

7.5.6.2.2 Power Supply

The HVPS modules provide variable 0 to 200 V-dc power the LPRM detectors. The HVPS current rating is 120 mA. The 386SX computer module controls the HVPS output voltage and current via the data bus and a digital-to-analog (D/A) converter on the broadcaster module.

Two independently controlled HVPS modules are used per APRM chassis. One module provides the normal supply of high voltage and powers all LPRM detectors connected to the APRM chassis. The second module serves as a backup power supply and provides power to a bypassed LPRM detector selected for current/voltage curve plotting. If the self-test detects failure of the normal power supply, the backup power supply automatically switches to supply high voltage to the LPRM detectors and a self-test alarm is issued. In this event, the APRM is incapable of performing current/voltage plotting until two fully functional HVPS modules are available.

The HVPS modules used for the LPRM detectors shall comply to the applicable sections of NRC RG 1.152-1985 “Criteria for Programmable Digital Computer System Software in Safety Related Systems of Nuclear Power Plants,” IEEE 603-1991 “Standard Criteria for Safety Systems for Nuclear Power Generating Stations,” and IEEE 7-4.3.2-1993 “Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations.”

7.5.6.2.3 Physical Arrangement

The LPRM system includes LPRM detectors located throughout the core at different axial heights. Figure 7.5-10, sheet 1, illustrates the LPRM detector radial layout scheme which provides a detector assembly at every fourth intersection of the narrower of the water channels around the fuel bundles (narrow-narrow water gap). Thus, every narrow-narrow water gap has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant.

Thirty-one LPRM detector assemblies, each containing 4 fission chambers, are distributed to monitor 4 horizontal planes throughout the core. The detector assemblies (drawing no. S-15584) are inserted into the core in spaces between the fuel assemblies through thimbles which are mounted permanently at the bottom of the core lattice and which penetrate the bottom of the reactor vessel. These thimbles are welded to the reactor vessel at the penetration point. They extend down into the access area below the reactor vessel where they terminate in a flange which mates to the mounting flange on the incore detector assembly. The detector assemblies are locked at the top end to the top fuel guide by means of a spring-loaded plunger. This type of assembly is referred to as top entry - bottom connect, since the assembly is inserted through the top of the core and penetrates the bottom of the reactor vessel. Special water-sealing caps are placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents the loss of reactor coolant water upon removal of an assembly and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

Each LPRM detector assembly contains four miniature fission chambers with an associated solid sheath cable. Each fission chamber produces a current which, when coupled with the LPRM signal-conditioning equipment, provides the desired scale deflection throughout the design lifetime of the chamber. Each individual chamber of the assembly is a moisture-proof, pressure-sealed unit. Each assembly also contains a calibration tube for a TIP. The enclosing tube around the entire assembly contains holes evenly spaced along its length. These holes allow circulation of the reactor coolant water to cool the fission chambers. Numerous tests have been performed on the chamber assemblies including tests of linearity, lifetime, gamma sensitivity, and cable effects (reference 1). These tests and experience in operating reactors provide confidence in the ability of the LPRMs to monitor neutron flux to the design accuracy throughout the design lifetime.

The 4 miniature fission chambers used on each assembly are designed to operate up to a temperature of 600°F and a pressure of 1250 psig. The chambers are vertically spaced in the LPRM detector assemblies in such a manner as to give adequate axial coverage of the core, complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each miniature chamber consists of two concentric cylinders which act as electrodes. The inner cylinder, the collector, is mounted on insulators and is separated from the outer cylinder by a small gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the uranium coated outer electrode. The chamber is operated at a polarizing potential of ~ 100 V. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage.

7.5.6.2.4 Signal Conditioning

The current signals from the LPRM detectors are transmitted to the LPRM input module (LIM) in the APRM chassis located in the MCR. The current signal from a chamber is transmitted directly to its amplifier through coaxial cable. The amplifier is a linear current amplifier whose voltage output is proportional to the current input and, therefore, is proportional to the magnitude of the neutron flux. The amplifier output is "read" by digital processing electronics. The digital electronics apply hardware gain corrections, perform filtering, and apply the LPRM gain factors. The digital electronics provide suitable output signals for the computer, recorders, and annunciators. The LPRM amplifiers also isolate the detector signals from the rest of the processing so that an individual fault in one LPRM signal path will not affect other LPRM signals.

The LPRM signals are indicated on the reactor console. When a central control rod is selected for movement, the LPRM values associated with the nearest 16 LPRM detectors are displayed on the operator display assemblies. Each of the four axially spaced LPRM detector signals from each of the four LPRM assemblies is displayed. The operator can readily obtain the readings of all the LPRM amplifiers by either selecting the control rods in the correct order or selecting LPRM screens on the operator display assembly.

7.5.6.2.5 Trip Functions

The trip function for the LPRM provides trip signals to activate displays, instrument inoperative signals, and annunciators. The outputs for the trip functions are designed to go to the "tripped" state on loss of power to the processing electronics. Table 7.5-3 indicates the trips.

The trip levels can be adjusted to an accuracy of ± 0.1% and a hysteresis of ± 1% flux.

The seals in the LPRM gradually undergo fast neutron damage, and leakage may occur between the chamber and its associated cable. Once the seal has started leaking, the nonlinearity of the LPRM increases to a nominal ± 2% of full scale. The leaking seal LPRM should be recalibrated as soon as possible.

7.5.6.3 Power Generation Evaluation

The LPRM system, as calibrated by the TIP system, provides detailed information about the neutron flux throughout the reactor core.

LPRM distribution is determined by extensive calculations and experimental procedures. Individual failed chambers can be bypassed, and neutron flux information for a failed chamber location can be interpolated from nearby chambers. A substitute reading for a failed chamber can be derived from an octant-symmetric chamber, or a gamma flux indication can be obtained by insertion of a TIP to the failed chamber position.

LPRM outputs provide the functions required in the LPRM power generation design basis. Each output is electrically isolated so that an event (grounding the signal or applying a stray voltage) on the reception end does not destroy the validity of the LPRM signal. Tests and experience attest to the ability of the detector to respond proportionally to the local neutron flux changes.

7.5.6.4 Inspection and Testing

LPRM channels are calibrated using data from previous full-power runs and TIP data, and are tested by procedures in the applicable instruction manual.

7.5.7 AVERAGE POWER RANGE MONITOR SYSTEM

7.5.7.1 Safety Design Bases

A. The design of the APRM system is capable of generating a scram trip signal in response to average neutron flux increases resulting from either AOOs or thermal-hydraulic instabilities in time to prevent fuel damage.

B. The design of the APRM system is consistent with the requirements of the safety design basis of the RPS.

7.5.7.2 Power Generation Design Bases

A. The APRM system shall provide a continuous indication of average reactor power from 0.0 to 125% of rated reactor power.

B. The APRM system is capable of providing trip signal for blocking rod withdrawal when the average reactor power exceeds preestablished limits set to prevent scram actuation.

C. The APRM system provides a reference power level for use in the RBM system.

7.5.7.3 Description

7.5.7.3.1 Identification

The APRM system has four APRM channels, each of which uses input signals from a number of LPRM channels. Each of the four APRM channels provides inputs to four two-out-of-four voter channels. Two of the voter channels are associated with each of the RPS trip systems. All four APRM channels are associated with both RPS trip systems in that they provide inputs to each of the four voter channels (figure 7.5-7, sheet 2 of 5).

7.5.7.3.2 Power Supply

Each APRM chassis receives power from the low-voltage power supply (LVPS) module connected to 120 V-ac RPS bus A and one LVPS module connected to 120 V-ac RPS bus B (figure 7.5-7, sheet 1 of 5). Each APRM's two-out-of-four voter logic module receives power from the RPS bus associated with the APRM channel's trip output, as well as from the APRM chassis. Electrical isolation between power sources and associated circuits is provided.

7.5.7.3.3 Signal Conditioning

The APRMs use digital electronic equipment that averages the output signals from a selected set of LPRMs, generates trip outputs via the two-out-of-four voter channels (paragraph 7.5.7.3.4), and provides signals to readout equipment. Each APRM channel can average the output signals from up to 31 LPRM channels. Assignment of LPRM channels to an APRM is shown on drawing no. H-16561. The letters at the detector locations shown on drawing no. H-16561, refer to the axial positions of the detectors in the LPRM detector assembly. Position A is the bottom position, positions B and C are above position A, and position D is the topmost LPRM detector position. The pattern provides LPRM signals from all four core axial LPRM detector positions throughout the core. Some LPRM detectors may be bypassed, but the averaging logic automatically corrects for these detectors by removing them from the average. The APRM value calculated from the LPRM inputs is adjusted by a digitally entered factor to allow calibration of the APRM to core thermal power based upon heat balance.

Each APRM channel calculates a flow signal that is representative of total core flow and is used to determine the APRM's flow-biased rod block and scram setpoints (figure 7.5-7, sheet 5 of 5). Each signal is determined by summing the flow signals from the two-recirculation loops. These signals are sensed from two flow elements, one in each recirculation loop. The differential pressure from each flow element is routed to four differential pressure transducers (eight total).

The signals from two differential pressure transducers, one from each flow element, are routed to two inputs to the APRM digital electronics.

All APRM channels are powered redundantly via intermediate low voltage dc power supplies, from both the "A" and "B" RPS ac power buses. The LPRM signal processing equipment is powered by the same sources as the associated APRM channels.

7.5.7.3.4 Trip Function

The digital electronics for the APRMs provides trip signals directly to the RMCS and via the APRM two-out-of-four voter channels to the RPS. Any two unbypassed APRM channels, via the APRM two-out-of-four voter channels, can initiate an RPS trip in both RPS trip systems. Any unbypassed APRM can initiate a rod block, depending upon the position of the reactor mode switch.

Table 7.5-4 lists the APRM trip functions. Section 7.7 describes in more detail the APRM rod block functions.

The APRM simulated thermal power upscale rod block and scram trip setpoints are varied as a function of reactor recirculation flow. The slope of the upscale rod block and scram trip response curves is set to track the required trip setpoint with recirculation flow changes.

At least two unbypassed APRM channels must be in the upscale or inoperative trip state to cause an RPS trip output from the APRM two-out-of-four voter channels. In that condition, all four voter channels will provide an RPS trip output, two to each RPS trip system. If only one unbypassed APRM channel is providing a trip output, each of the four APRM two-out-of-four voter channels will have a half-trip, but no trip signals will be sent to the RPS. The trips from one APRM can be bypassed by operator action in the MCR. Trip outputs to the RPS are transmitted by removing voltage to a relay coil, so that loss of power results in actuating the RPS trips. A simplified APRM/RPS interface circuit arrangement is shown in figure 7.5-7, sheet 3 of 5.

In the startup mode of operation, the APRM "fixed" upscale trip setpoint is set down to a low level to assist the operator in startup procedures. The trip function is provided in addition to the existing IRM upscale trip in the startup mode. The trip settings are listed in table 7.5-4.

The trip functions are performed by digital comparisons in APRM electronics. The APRM flux value is developed by averaging the LPRM signals and adjusting the average, using the gain adjustment factor from heat balance calculations, to be APRM power. To calculate simulated thermal power the APRM power is processed through a first order filter with a 6-s time constant. These calculations are all performed by the digital processor and result in a digital representation of APRM and simulated thermal power. For each RPS trip and rod block alarm, the APRM power or simulated thermal power, as applicable (table 7.5-4), is digitally compared to the setpoint that was previously entered and stored. If the power value exceeds the setpoint, the applicable trip is issued.

7.5.7.4 <u>Safety Evaluation</u>

Each APRM derives its signal from LPRM information. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design basis of the RPS. Four APRM channels allow one bypass and one random failure in each trip system and still satisfy the RPS safety design basis.

Figure 7.5-8 illustrates the ability of the APRM subsystem to track core power versus coolant flow starting at 100% power and 100% flow to below the 65% flow point. Figure 7.5-9 illustrates the ability of the APRM to respond to control rod motion. The conditions for this are selected from the most restrictive case. The figure illustrates a full withdrawal of a control rod from limiting conditions at rated power. Normal control rod manipulation results in good agreement (< 5% deviation on the worst APRM) through a wide range of power levels.

The safety analysis provided in HNP-2-FSAR chapter 15 demonstrates the adequacy of the flow-referenced APRM scram setpoint in preventing fuel damage as a result of an AOO.

7.5.7.5 Power Generation Evaluation

The APRM system provides the operator with four continuous recordings of the average reactor power. The rod blocking function prevents operation above the region defined by the design power response to recirculation flow control. The flow signal used to vary the rod block level is supplied from the recirculation system flow instrumentation. Four separate transmitters on each of two recirculation loops, eight total (figure 7.5-7, sheet 5 of 5), route output signals to four APRM chassis. Each APRM processes and sums transmitter signals (two total, one per loop) from its flow transmitter inputs. Each APRM sends its total flow signal to both RBMs to provide an alarm when the difference between maximum and minimum values for total recirculation flow exceeds setpoint. Each APRM uses the flow signal it processes "as is" for APRM and OPRM trip functions. Each RBM uses the flow signal it receives from its "home" APRM or alternate APRM if the "home" APRM is unavailable. Each APRM compares its own processed flow signal to a high setpoint, and issues a rod block and alarms if the setpoint is exceeded (table 7.5-4). Bypass of the APRM channel bypasses the flow functions (no separate flow signal bypass). Because any one of the APRMs can initiate a rod block, this function has a high level of redundancy and satisfies the power generation design basis. One APRM channel may be bypassed. In addition, a minimum of 17 LPRM inputs is required for each APRM channel to be operative. If the number is < 17, an automatic APRM inoperative trip is generated.

7.5.7.6 Inspection and Testing

APRM channels are calibrated using data from previous full-power runs and are tested using procedures in the applicable instruction manual. Each APRM channel can be individually tested for the operability of the APRM scram and rod blocking functions by introducing test signals.

7.5.8 ROD BLOCK MONITOR SYSTEM

7.5.8.1 Power Generation Design Bases

A. The RBM system is designed to assist the operator in preventing violation of the fuel-cladding integrity safety criteria as a result of a single rod withdrawal error under the worst permitted condition of RBM bypass.

B. The RBM system provides a signal to permit operator evaluation of the change in the local relative power level during control rod movement.

C. The RBM system is designed and built to meet appropriate protection system criteria.

7.5.8.2 Description

7.5.8.2.1 Identification

The RBM system has two RBM channels, each using input signals from a number of LPRM channels. A trip signal from either RBM channel can initiate a rod block. One RBM channel may be bypassed without loss of subsystem function. The RBM receives LPRM signals and the simulated thermal power value from an "assigned master" APRM and receives the identity of the selected control rod from the rod control system.

7.5.8.2.2 Power Supply

Each RBM chassis receives power from one LVPS module connected to 120-V-ac RPS bus A and LVPS module connected to 120-V-ac bus B (figure 7.5-7, sheet 1 of 5).

7.5.8.2.3 Signal Conditioning

The RBM signal is generated by averaging a set of LPRM signals. The LPRM signals used depends upon the control rod selected. Upon selection of a rod for withdrawal or insertion, the two RBM channels automatically select the conditioned signals, from the LPRMs around that rod. (Figure 7.5-10, sheet 1 of 2, shows examples of the four possible LPRM/selected rod assignment combinations.) For a typical nonedge rod, each RBM channel averages LPRM inputs from two of the four B-position and D-position detectors, and all four of the C-position detectors (figure 7.5-10, sheet 2 of 2). A-position LPRM detectors are not included in the RBM averages, but are displayed in the MCR. When a rod near, but not at, the edge of the core is selected, where there are fewer than four but at least two LPRM strings around the rod, the number of detectors used by the RBM channels is either six or four depending upon how many LPRM strings are available. If a detector in the LPRM system was bypassed, the detector is automatically deleted from the RBM processing, and the averaging logic is adjusted to average only the remaining detectors.

After selection of a control rod, each RBM channel calculates the average of the related LPRM detectors and calculates a gain factor that will adjust the average to 100. Thereafter, until another rod is selected, the gain factor is applied to the LPRM average to obtain the RBM signal value. The RBM signal value is compared to RBM trip setpoints (paragraph 7.5.8.2.4).

When a peripheral rod is selected, or if the simulated thermal power value from the RBM's associated APRM is below the automatic bypass level (~ 30% power), the RBM function is automatically bypassed, the rod block outputs are set to "permissive," and the RBM average is set to zero.

The RBM chassis is also assigned some APRM support functions to simplify the overall system architecture. The RBM provides the communication path for APRM information to the plant computer and provides the path for downloading LPRM and APRM gain adjustment factors and reference values. The RBM chassis compares the total flow signals developed by each APRM and issues an alarm if the difference exceeds a preset value.

7.5.8.2.4 Trip Function

The RBM supplies a trip signal to the RMCS to inhibit control rod withdrawal. The trip is initiated whenever the RBM signal value exceeds the rod block setpoint. There are three rod block setpoints that are a function of the core thermal power. The three setpoints are each a percentage above the RBM initial value of 100. The particular setpoint applied is selected based upon the simulated thermal power value from the RBM's associated APRM channel. (An alternate APRM channel is assigned and is automatically used for inputs if the primary APRM channel is bypassed or inoperative.) Higher APRM simulated thermal power values select a lower setpoint. That is, at higher power levels, the percentage increase in the RBM value allowed is less than at lower power levels. The power ranges over which each is implemented are adjustable. The ranges of adjustability are given in NEDC-30474-P. The specific values of the setpoints and the power ranges of applicability are given in the plant Technical Specifications.

Either RBM channel can prevent rod movement. The operator can bypass one of the two RBMs at any time. Either RBM can inhibit control rod withdrawal (drawing no. H-19931).

7.5.8.2.5 Isolation Separation and Redundancy

The following features are included in RBM design:

A. Redundant, separate, isolated RBM channels are provided.

B. Redundant, separate, isolated rod selection information (including isolated contact for each rod selection pushbutton) is provided directly to each RBM channel.

C. Independent, separate, isolated APRM reference signals are inputted to each RBM channel.

D. Independent, separate, isolated RBM level readouts and status displays are provided from the RBM channels.

E. Independent, separate, isolated rod block signals are outputted from the RBM channels to the RMCS.

The RBM system is designed to meet the requirements of IEEE 279, except for physical limitations as follows:

Limitation	Explanation
A single rod select push-button is used for selection of a rod.	A single pushbutton for selection of a rod is provided, but redundant contacts are provided on the pushbutton.
The rod withdrawal block outputs from the RBM are carried to a single cabinet for connection into the RMCS.	Each RBM activates a distinctive annunciating block (i.e., RBM A activates annunciating rod block A; RBM B activates annunciating rod block B) used in different portions of RMCS circuits. Both RBMs actuate a single nonannunciating rod block used in one portion of RMCS circuit (section 7.7).
A single switch allows one-out-of-two bypasses of RBM outputs to the RMCS.	A single switch is provided; however, isolation requirements are maintained.
Separability and redundancy of input signals are provided.	These features improve similarity of channel responses.

7.5.8.3 Power Generation Evaluation

Motion of a control rod causes the LPRMs adjacent to the control rod to respond strongly to the change in power in the region of the rod in motion. NEDC-30474-P illustrates the calculated response of the two RBMs to the full withdrawal of a selected control rod from a region in which the design limits on power and flow existed.

The rod block setpoint halts rod motion before MCPR goes below the safety limit. This is true even with the LPRMs in the adjacent and nearest power range detector assemblies failed.

7.5.8.4 Inspection and Testing

The RBM channels are tested and calibrated using procedures given in the applicable instruction manuals. The RBMs are functionally tested by introducing test signals into the RBM channels.

7.5.9 TRAVERSING INCORE PROBE SYSTEM

7.5.9.1 Power Generation Design Bases

A. The TIP system is capable of providing a signal proportional to the gamma flux distribution at selected small axial intervals over the regions of the core where power range detector assemblies are located. This signal is of high precision to allow reliable calibration of LPRM gains.

B. The TIP system provides accurate indication of the position of the flux measurement to allow pointwise or continuous measurement of the axial gamma flux distribution.

7.5.9.2 Description

7.5.9.2.1 Identification

The TIP system includes four TIP channels each of which has the following components:

- One TIP.
- One drive mechanism.
- One indexing mechanism.
- Up to 10 incore guide tubes.
- One chamber shield.

The system allows calibration of LPRM signals by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core. The guide tubes inside the reactor are divided into groups. Each group has its own associated TIP channels. The assignment of LPRM strings to the 4 TIP channels is shown in figure 7.5-11.

7.5.9.2.2 Physical Arrangement

A TIP drive mechanism uses an ion chamber attached to a flexible drive cable, which is driven from outside the primary containment by a gear box assembly. The flexible cable is contained by guide tubes that continue into the reactor core. The guide tubes are a part of the power range detector assembly and are specially prepared to provide a durable low-friction surface. The indexing mechanism allows the use of a single detector in any one of 10 different tube paths. The tenth tube is used for TIP cross calibration with the other TIP channels. The control system provides both manual and semiautomatic operation. The TIP signal is amplified and can be displayed on a meter. Core position versus gamma flux can be recorded in the MCR on an X-Y recorder. A block diagram of the drive system is shown in figure 7.5-12.

The heart of each TIP channel is the gamma TIP probe (figure 7.5-13) consisting of a detector (ion chamber) and the associated signal drive cable. The gamma TIP is a direct replacement for the previously used neutron TIP. The gamma TIP is designed to operate in a gamma flux field of 2.8 x 10^9 R/h in the same neutron flux field as the previous (neutron) TIP. The operating voltage is ~ 100 V dc.

The signal current from the detector is transmitted from the TIP to amplifiers and readout equipment by means of a signal cable which is an integral part of the mechanical drive cable. The outer sheath of the drive cable is constructed of carbon steel in a helix array. The cable-drive mechanism engages this helix to effect movement in and out of the guide tubes. The inner surface of the guide tubing between the reactor vessel and the drive mechanism is coated with a ceramic-bonded lubricant to reduce friction. Within the reactor vessel, the guide tubing inner surface is nitrided.

The cable-drive mechanism contains the drive motor, the cable takeup reel, an analog probe position transducer for the recorder, and an encoder to provide digital pulses to the control unit for positioning the TIP at specific locations along the guide tube.

The drive mechanism inserts and withdraws the TIP and its cable from the reactor and provides detector position indication signals. The drive mechanism includes a motor controller, electrical connector panel, and a motor and drive-gear box, which drives the cable in the manner of a rack and pinion. A variable-speed motor is used providing a high speed for insertion and withdrawal (90 ft/min) and a low speed for scanning the reactor core (7.5 ft/min). The drive motor is equipped with a friction brake to prevent overshoot and an overload release clutch that disengages when the torque on the drive cable reaches 250 in.-lb. (See drawing no S-15070.)

A takeup reel is included in the cable-drive mechanism to coil the drive cable as it is withdrawn from the reactor. This reel makes it possible to connect the TIP and its cable to the amplifier through a connector.

The analog position transducer and the digital encoder are also driven directly from the output shaft of the cable drive motor. The analog position signal from a transducer and a flux amplifier output are used to plot gamma flux versus incore position of the TIP. The TIP position signal is also available to the process computer. The position transducer is used to position the TIP in the guide tube through the control logic with a linear position accuracy of ± 1 in. The position transducer can control TIP positions at the top of the core for initiation of scan and at the bottom of the core for changing to fast withdrawal speed.

When the system is not in use, the detector probe can be completely withdrawn to a position in the center of the chamber shield.

A circular transfer machine with 10 indexing points functions as an indexing mechanism. Nine of these locations are for the guide tubes associated only with that particular TIP channel. The tenth location is for the guide tube common to all the TIP channels. Indexing to a particular tube location is accomplished manually at the control panel by means of a position selector switch which energizes the electrically actuated rotating mechanism.

The tube transfer mechanism is part of the indexing mechanism and consists of a fixed circular plate containing 10 holes inside the primary containment which mate to a rotating single hole plate outside the primary containment.

The rotating plate aligns and mechanically locks with each fixed hole position in succession. The indexing mechanism is actuated by a motor-operated rotating drive. Electrical interlocks prevent the indexing mechanism from changing positions until the probe cable has been completely retracted beyond the parked position. Additional electrical interlocks prevent the cable-drive motor from moving the cable until the transfer mechanism has indexed to the preselected guide tube location. (See drawing no. H-19965.)

A valve system is provided with a valve on each guide tube entering the primary containment. These valves are closed except when the TIP subsystem is in operation. A ball valve and a cable-shearing valve are mounted in the guide tubing just outside of the primary containment. They prevent the loss of reactor coolant in the event a guide tube ruptures inside the reactor vessel. A valve is also provided for a nitrogen gas purge line to the indexing mechanisms. A guide-tube ball valve opens only when the TIP is being inserted. The shear valve is used only if a leak occurs when the TIP is beyond the ball valve and power to the TIP system fails. The shear valve, which is controlled by a manually operated keylock switch, can cut the cable and close off the guide tube. Subsequent to the requirement for containment isolation, the operator should observe a green indicating light for each TIP machine which tells him that the associated probe has been withdrawn and that the isolation ball valve is closed. This lamp is illuminated when either the normal isolation ball valve or the shear valve is closed. Should the operator fail to receive a green light indication, he could attempt to withdraw the probe from the TIP control panel in the MCR. If this action failed, he would then initiate operation of the shear valve. The requirement for containment isolation is infrequent and the coincident use of the TIP system at such a time, together with a probe failing to withdraw leads to a very low probability for the overall event. However, assuming such an event, the leakage path is extremely small, considering a 1/4-in. bore tube which contains the TIP cable. The leakage is considered to be virtually zero and would leave adequate time for the operator to initiate the shear valves after his determination that such action was necessary. Having regard for the unlikely nature of the event coupled with the minimal leakage which could result, it is felt that automatic initiation of the shear valves is not required. Furthermore, automatic initiation of these valves would increase the possibility of inadvertent operation with the attendant operational problem of effecting a repair. The shear valves are actuated by detonation squibs. The continuity of the squib circuits is monitored by indicator lights in the control room.

The TIP system is also designed to prevent automatic reopening of the ball valves upon reset of the containment isolation logic. This feature complies with the requirements of NUREG-0737, Item II.E.4.2, Containment Isolation Dependability. A latching circuit is included as part of the TIP system isolation logic, making it necessary for a manual switch to be operated before the ball valves can be manually opened after reset of the primary containment isolation system, thus requiring deliberate operator action.

A guide tube ball valve is normally deenergized and in the closed position. When the TIP starts forward, the valve is energized and opens. As it opens, it actuates a set of contacts which give a signal light indication at the TIP system control panel and bypasses an inhibit limit switch which automatically stops TIP motion if the ball valve does not open on command. (See drawing no. H-19965.)

7.5.9.2.3 Signal Conditioning

The readout instruments and electrical controls for the TIP machines are mounted in a cabinet in the MCR. Since there are several groups of guide tubes, each with an associated TIP machine, there are also several groups of readout equipment controls mounted in the cabinet. Each set of readout equipment consists of a dc amplifier and a dc power supply for the TIP polarizing voltage. A common X-Y recorder can be used to record the flux variations of each scan. An X-Y output is provided for use by the process computer. The probe and cable leakages contribute < 1% of indicated reading. For normal operating conditions, the flux amplifier is linear to within ± 1.0% of full scale and drifts < 1.0% of full scale during a 1000-h period at design operating conditions.

7.5.9.3 Power Generation Evaluation

An adequate number of TIP machines is supplied to assure that each LPRM assembly can be probed by a TIP and one LPRM assembly (the central one) can be proved by every TIP to allow inter-calibration. The system design allows semiautomatic operation for LPRM calibration and process computer use. The TIP machines can be operated manually to allow pointwise flux mapping.

7.5.9.4 Inspection and Testing

The TIP system equipment is tested and calibrated using heat balance data and procedures as described in the instruction manual.

7.5.10 OSCILLATION POWER RANGE MONITOR

The OPRM monitors the core for power oscillations indicative of a core thermal-hydraulic instability. The OPRM uses "cells" of detectors selected from the total available to the APRM channel. The criteria used to select the cells include consideration of all anticipated "phases" of oscillations. The Boiling Water Reactor Owners' Group (BWROG) defined the instability OPRM detect-and-suppress trip function utilizing LPRM inputs from the LPRM function. These signals are evaluated using algorithms and logic defined by the BWROG.[2] The OPRM is designed to detect reactor core thermal-hydraulic instability and provide appropriate readouts, trips, and alarms (figure 7.5-7, sheet 2 of 5).

7.5.10.1 Safety Design Bases

A. The design of the OPRM system is capable of generating a scram trip signal, in response to neutron flux oscillations resulting from thermal-hydraulic instability, in time to prevent fuel damage.

B. The design of the OPRM system is consistent with the requirements of the safety design basis of the RPS.

7.5.10.2 Power Generation Design Bases

The OPRM system is capable of providing an alarm signal for the operator when neutron flux oscillations exceed preestablished limits set to prevent scram actuation.

7.5.10.3 Description

7.5.10.3.1 Identification

The OPRM system has four OPRM channels each of which uses input signals from a number of LPRM channels. Each of the four OPRM channels provides inputs to four APRM two-out-of-four voter channels. Two of the voter channels are associated with each of the RPS trip systems. All four OPRM channels are associated with both of the RPS trip systems in that they provide inputs to each of the four voter channels.

The OPRM functions are accomplished in the same equipment that performs the APRM functions (figure 7.5-7, sheet 2 of 5). The two-out-of-four voter channels perform a vote of the OPRM channel trip outputs separate from that performed for the APRM trip outputs. As a result, an OPRM trip in one channel and an APRM trip in another will not result in an RPS trip.

7.5.10.3.2 Power Supply

All OPRM channels operate in the APRM hardware that is powered redundantly, via intermediate low voltage dc power supplies, from the RPS ac power buses A and B. Each OPRM two-out-of-four voter channel receives power from the same 120-V-ac power as the RPS trip system with which it is associated (figure 7.5-7, sheet 1 of 5).

7.5.10.3.3 Signal Conditioning

The OPRMs use digital electronic equipment that separately averages the output signals from LPRMs in each OPRM "cell" (one to three LPRM detectors per cell). The OPRM equipment processes these cell averages through three algorithms, each monitoring a different dynamic characteristic (period-based, amplitude-based, and growth-based algorithm). The OPRM generates trip outputs via the two-out-of-four voter channels (paragraph 7.5.7.3.4) and provides signals to readout equipment when one or more of the instability algorithms has detected an instability condition for an operable OPRM cell. LPRM detectors are assigned to OPRM cells as an equipment setup action and are chosen to assure monitoring of all portions of the core. The algorithms include trip setpoints that are also entered as equipment setup action.

The OPRM logic receives the simulated thermal power signal and recirculation flow from the APRM processing logic. The OPRM trips are enabled only when the plant is operating above a minimum power level as indicated by the simulated thermal power signal (26%) and below a maximum recirculation flow value (≤ 60%). In all operating conditions outside this range, the OPRM trip is disabled.

All APRM channels are powered redundantly, via intermediate low voltage dc power supplies, from RPS ac power buses A and B. The LPRM signal processing equipment is powered by the same sources as the associated APRM channels.

The trip and alarm status of the OPRM channels is indicated at the local instrument and is either indicated or annunciated at the plant operator's panel.

7.5.10.3.4 Trip Function

The digital electronics for the OPRMs provides trip signals via the OPRM two-out-of-four voter channels to the RPS. Although the OPRM channels and APRM channels share the same two-out-of-four voter channel, the trip outputs of the OPRM function are voted separately from the APRM trip outputs.

At least two unbypassed OPRM channels must be in the trip state to cause a RPS trip output from the OPRM two-out-of-four voter channels. In that condition, all four-voter channels will provide a RPS trip output, two to each RPS trip system. If only one unbypassed OPRM channel is providing a trip output, each of the four two-out-of-four voter channels will have a half-trip, but no signals will be sent to the RPS. The trips from the OPRM can be bypassed by operator action in the control room; however in this state, both the OPRM and the associated APRM channels are bypassed. Trip outputs to the RPS are transmitted by removing voltage to a relay coil so that loss of power results in actuating the RPS trips. A simplified APRM/OPRM/RPS interface circuit arrangement is shown in figure 7.2-3.

The trip functions are performed by digital comparisons in the OPRM electronics. The LPRM flux values from each of the unbypassed detectors in an OPRM cell are combined, after processing by the LPRM system, by adding the detector values and filtering the sum to a steady-state average. The summation without filtering is compared to the average using the three different OPRM algorithms; i.e., the period-based, amplitude-based, and growth-based algorithms. If, after processing, the signals from the detectors in any of the OPRM cells in an OPRM channel indicate conditions or characteristics exceeding setpoint values, an OPRM trip is issued from that channel.

The OPRM trips are enabled only when the plant is operating above a minimum power level (26%) and below a maximum recirculation flow value (≤ 60%). In all operating conditions outside this range, the OPRM trip is disabled.

The trip and alarm status of the OPRM channels is indicated at the local instrumentation and indicated or annunciated at the plant operator's panel.

7.5.10.4 Safety Evaluation

Each OPRM derives its signal from information obtained from the LPRM system. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design basis of the RPS. There are four OPRM channels with the RPS outputs from each routed to each of four OPRM two-out-of-four voter channels. Two voter channels are associated with each RPS trip system. This configuration allows one OPRM channel to be bypassed, plus one failure, while still meeting the RPS safety design basis.

APRM power and simulated thermal power are adjusted periodically based upon heat balance to match true reactor power. This adjustment is made regularly at a rate sufficient to compensate for LPRM burnup and related change in APRM values. This assures that the OPRM function will be enabled when the reactor is operating at a power level at which thermal-hydraulic instabilities might occur, nominally at power levels above 30%. Recirculation coolant flow is also used to automatically bypass the OPRM trip when the reactor is operating at conditions of high core flow (nominally above 60%) when thermal-hydraulic osciallations are unlikely to occur. The setpoint for this automatic enable/disable function includes margin to accommodate variations in the relationship between recirculation drive flow and actual reactor core flow at operating conditions different from rated conditions.

The only OPRM algorithm for which safety credit is claimed is the period-based algorithm. The setpoints for that algorithm are established using a methodology developed by the BWROG and plant-specific fuel limits that provide adequate margin in the actual setpoints to assure safety limits are not exceeded even in the presence of failed or bypassed LPRM detector signals.

Each OPRM channel provides an inoperative alarm when the quantity of operating OPRM cells is less than the required minimum. The OPRM system provides the operator with front panel readouts showing the status of the OPRM system and an oscillation pre-trip alarm when one of the instability algorithms (period-based, amplitude-based, or growth-based) for an operable OPRM cell has exceeded user defined setpoints. The OPRM also provides an oscillation trip enable alarm that indicates when the reactor has reached the operating region where instability can occur and the osciallation trip output has been enabled (no longer bypassed). Together these readouts and alarms provide warnings to help assure the operator will know when the plant is operating in a region or at a condition that may lead to an OPRM trip, and allow the operator to take appropriate action.

7.5.10.5 Power Generation Evaluation

The OPRM system provides the operator with front panel readouts showing the status of the OPRM system and an oscillation pre-trip alarm when one of the instability algorithms (period-based, amplitude-based, or growth-based) for an operable OPRM cell has exceeded user defined setpoints. The OPRM also provides an oscillation trip enable alarm that indicates when the reactor has reached the operating region where instability can occur and the osciallation trip output has been enabled (no longer bypassed). Together these readouts and alarms provide warnings to help assure the operator will know when the plant is operating in a region or at a condition that may lead to an OPRM trip, and allow the operator to take appropriate action.

7.5.10.6 Inspection and Testing

OPRM channels require no direct calibration. APRM calibrations assure the OPRM channels receive calibrated LPRM, simulated thermal power, and recirculation flow signals. Each OPRM channel can be individually tested for the operability of the OPRM scram functions by introduced test signals.

REFERENCES

1. Morgan, W. R., "Incore Neutron Monitoring System for GE Boiling Water Reactors," APED-5706, November 1968.

2. "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," NEDC-32410P-A, Volumes 1 and 2, October 1995, and Supplement One, November 1997.

TABLE 7.5-1

SRM TRIPS

Trip Function	Trip Action
SRM upscale (high) or instrument inoperative	Rod block, light, annunciator
Detector retraction permissive (SRM downscale)	Bypass detector full-in limit switch when above preset limit, annunciator, light. Rod block when below preset limit with IRM range switches on first ranges
SRM period	Annunciator, light
SRM retraction permissive	Light when retraction permitted (above preset limits)
SRM downscale	Rod block, light, annunciator
SRM bypassed	Light

TABLE 7.5-2

IRM TRIPS

Trip Function	Trip Action
IRM upscale (high-high) or instrument inoperative	Scram, annunciator, light
IRM upscale (high)	Rod block, annunciator, light
IRM downscale	Rod block (except on most sensitive scale), annunciator, light
IRM bypassed	Light

TABLE 7.5-3

LPRM TRIPS

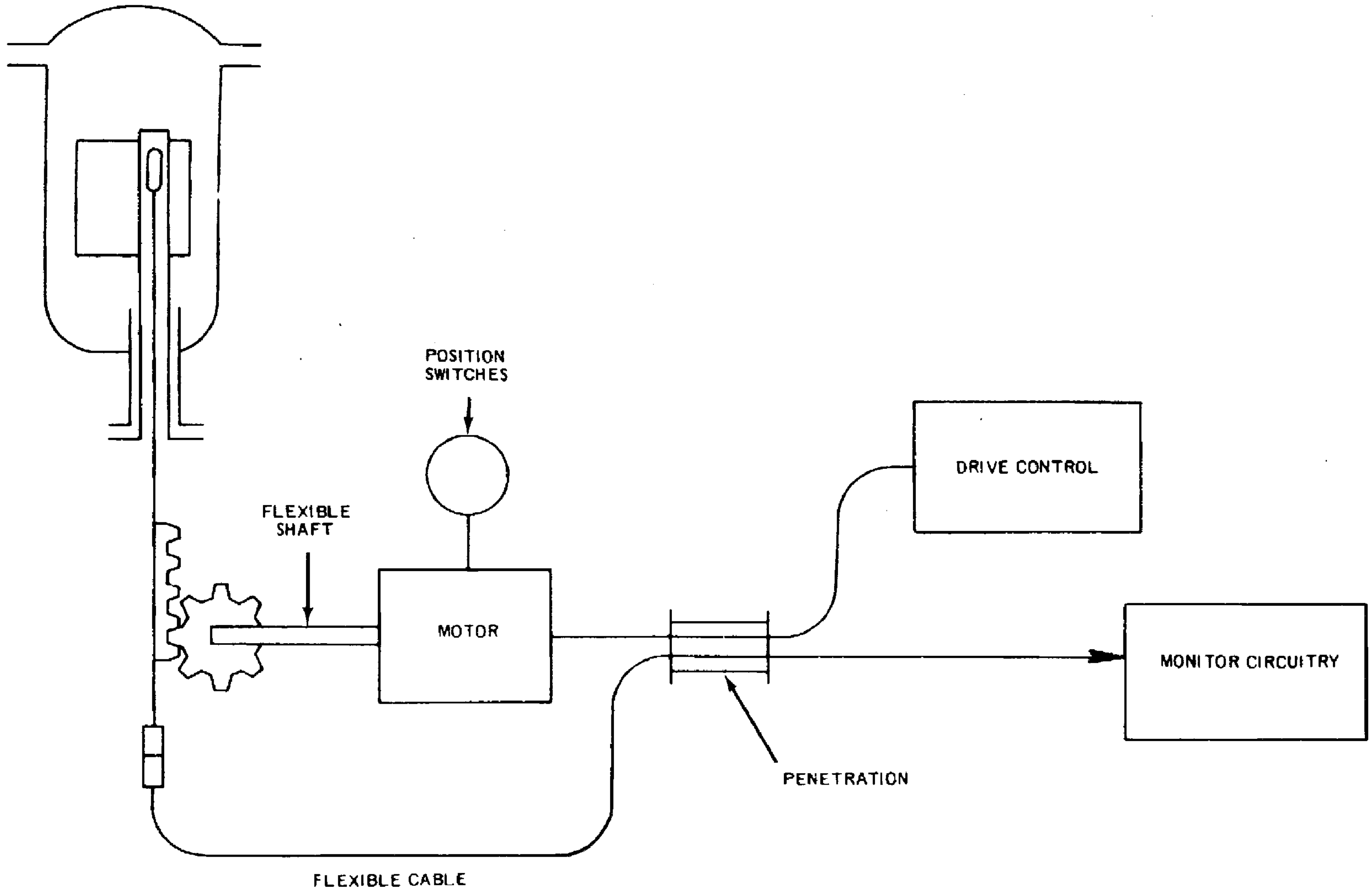
Trip Function	Trip Action
LPRM downscale	Operator display assembly and annunciator
LPRM upscale	Operator display assembly and annunciator
LPRM bypass	Operator display assembly and APRM averaging compensation

TABLE 7.5-4

APRM TRIPS

Trip Function	Trip Point Range	Nominal Setpoint	Action
APRM downscale	0% to 125%	(b)	Rod block, annunciator, operator display assembly
APRM upscale power range (high)	Varies with flow, intercept and slope adjustable	(b)	Rod block, annunciator, operator display assembly
APRM thermal power trip	Varies with flow, intercept and slope adjustable	(a)	Scram, annunciator, operator display assembly
APRM inoperative	Calibrate switch selected or too few inputs (LPRM)	Not in operating mode or < 17 inputs (LPRM)/APRM	Scram, annunciator, operator display assembly
APRM bypass	Manual switch	-	Operator display assembly
APRM upscale startup range (high)	7% to 27%	(b)	Rod block, annunciator, operator display assembly, IRM scram interlock
APRM upscale startup range (high-high)	10% to 30%	(a)	Scram, annunciator, operator display assembly IRM scram interlock
APRM upscale (high-high)	0% to 125%	(a)	Scram, annunciator, operator display assembly

a. Allowable values are listed in HNP-1 Technical Specifications. See HNP-1 Instrument Setpoint Index for actual setpoints.
b. See HNP-1 Instrument Setpoint Index for actual setpoints.



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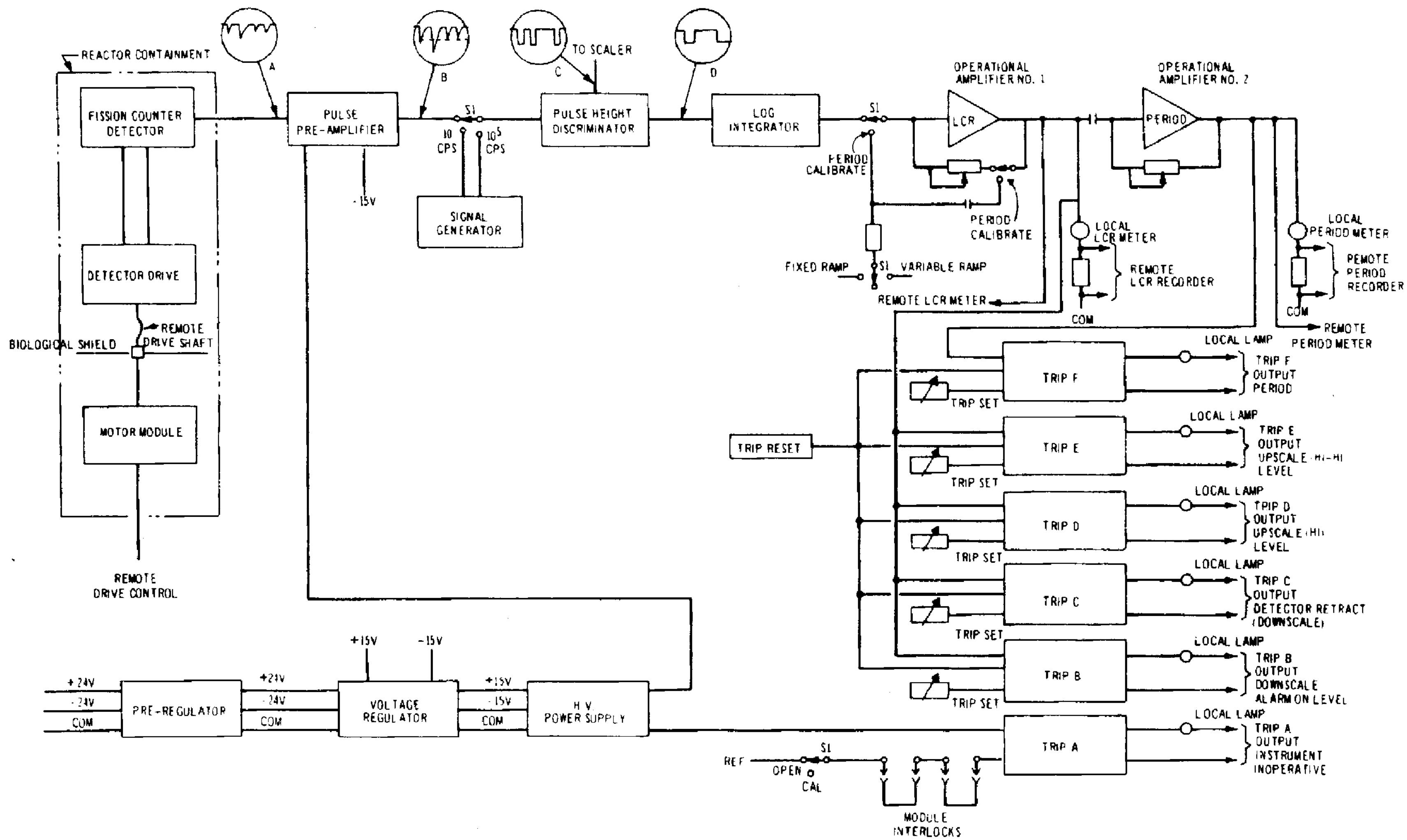
DETECTOR DRIVE SYSTEM SCHEMATIC

FIGURE 7.5-1



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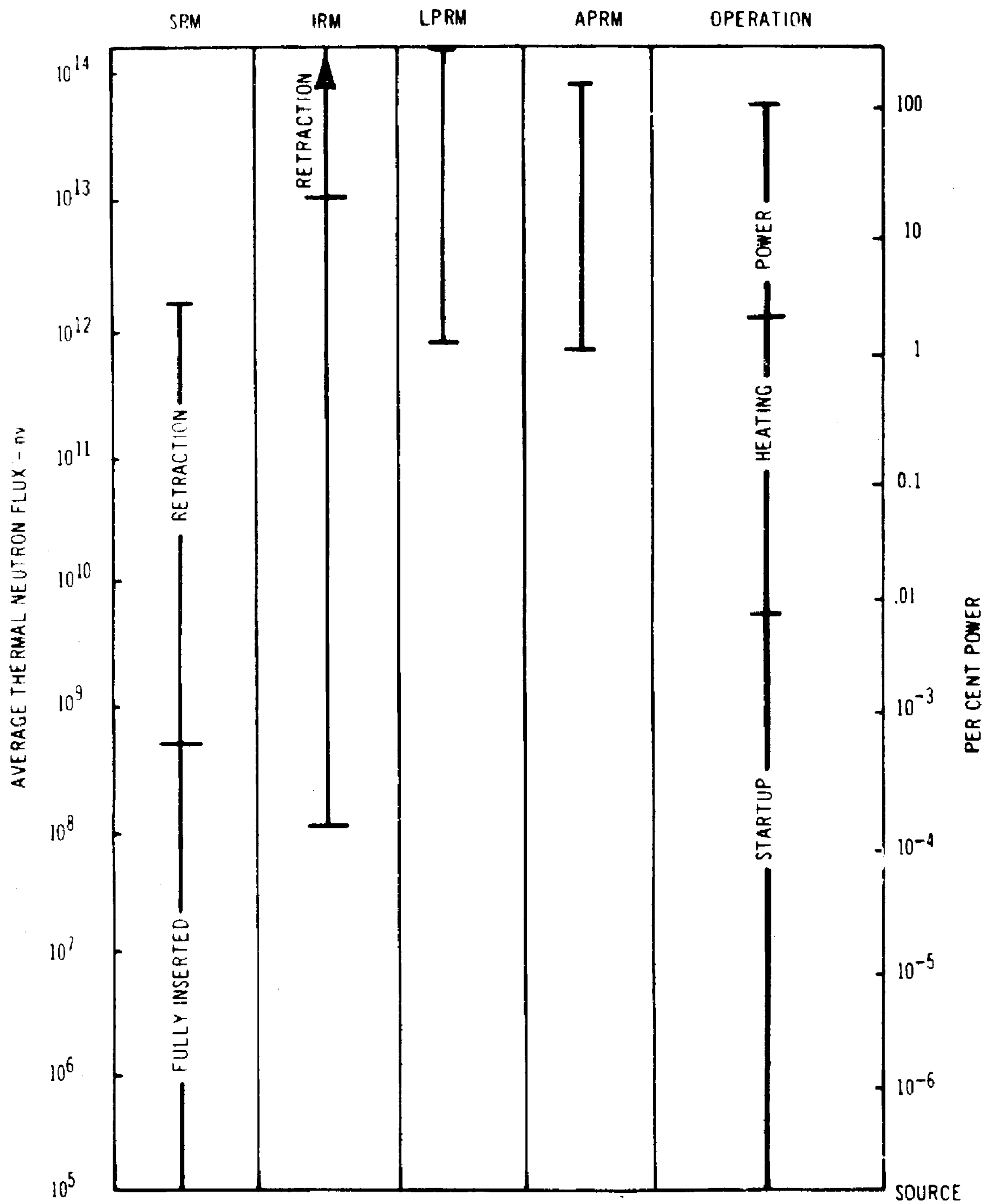
FUNCTIONAL BLOCK DIAGRAM OF SRM CHANNEL

FIGURE 7.5-2



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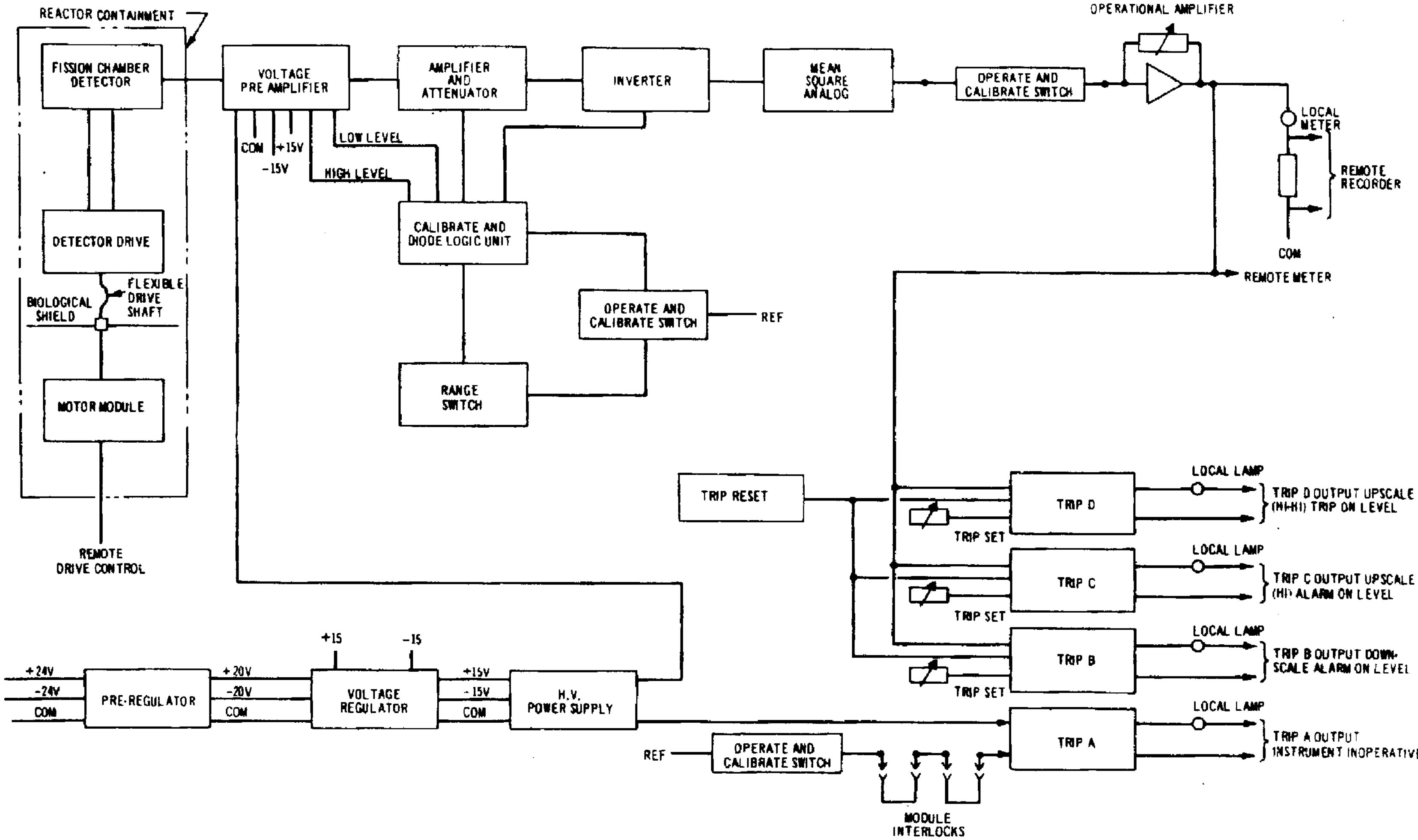
RANGES OF NEUTRON MONITORING SYSTEM

FIGURE 7.5-3



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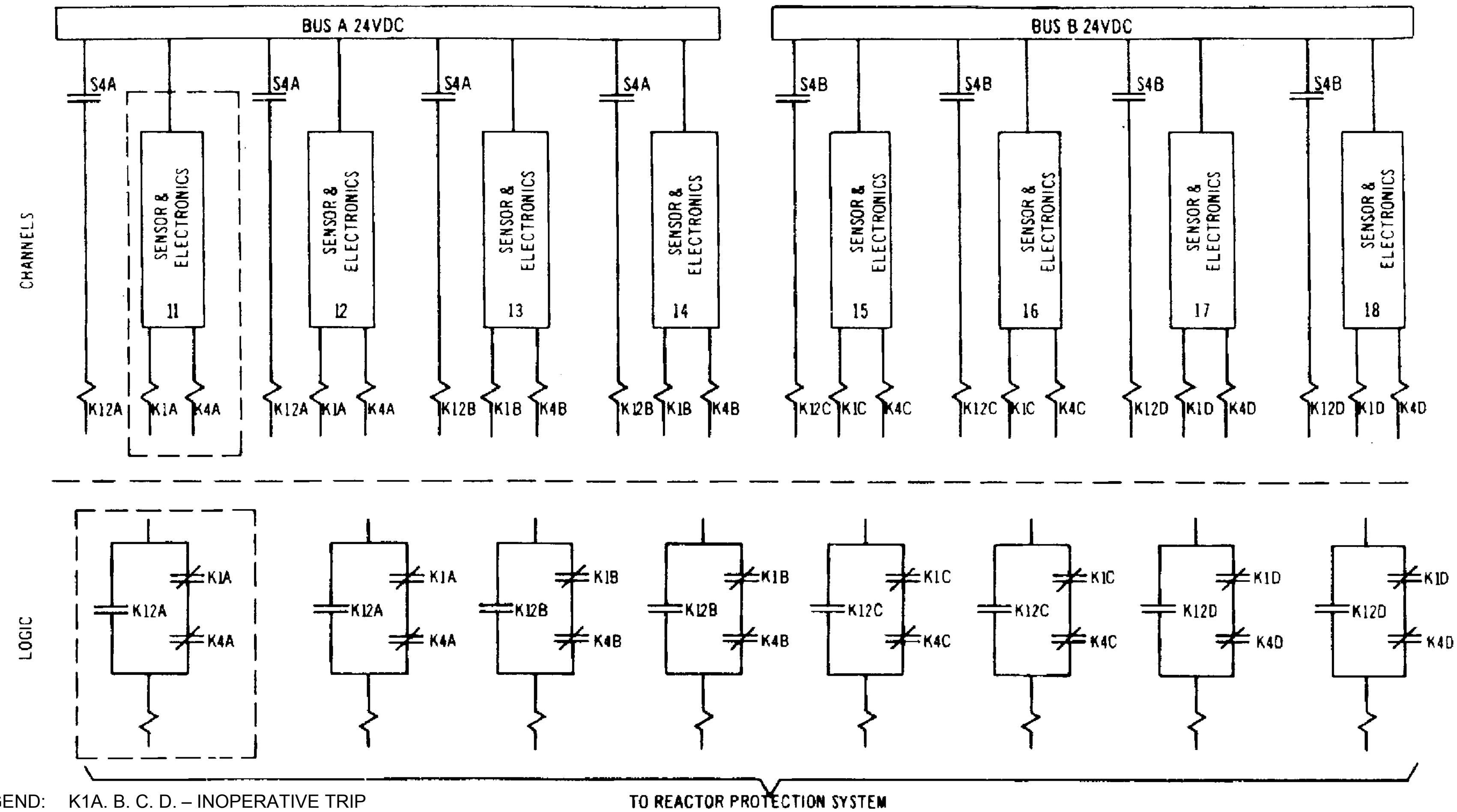
FUNCTIONAL BLOCK DIAGRAM OF IRM CHANNEL

FIGURE 7.5-4



LEGEND: K1A. B. C. D. – INOPERATIVE TRIP
K4A. B. C. D. – UPSCALE TRIP
S4A. B. – BYPASS SWITCH

NOTE: CONTACTS ALSO SHOWN IN NORMAL OPERATION POSITION

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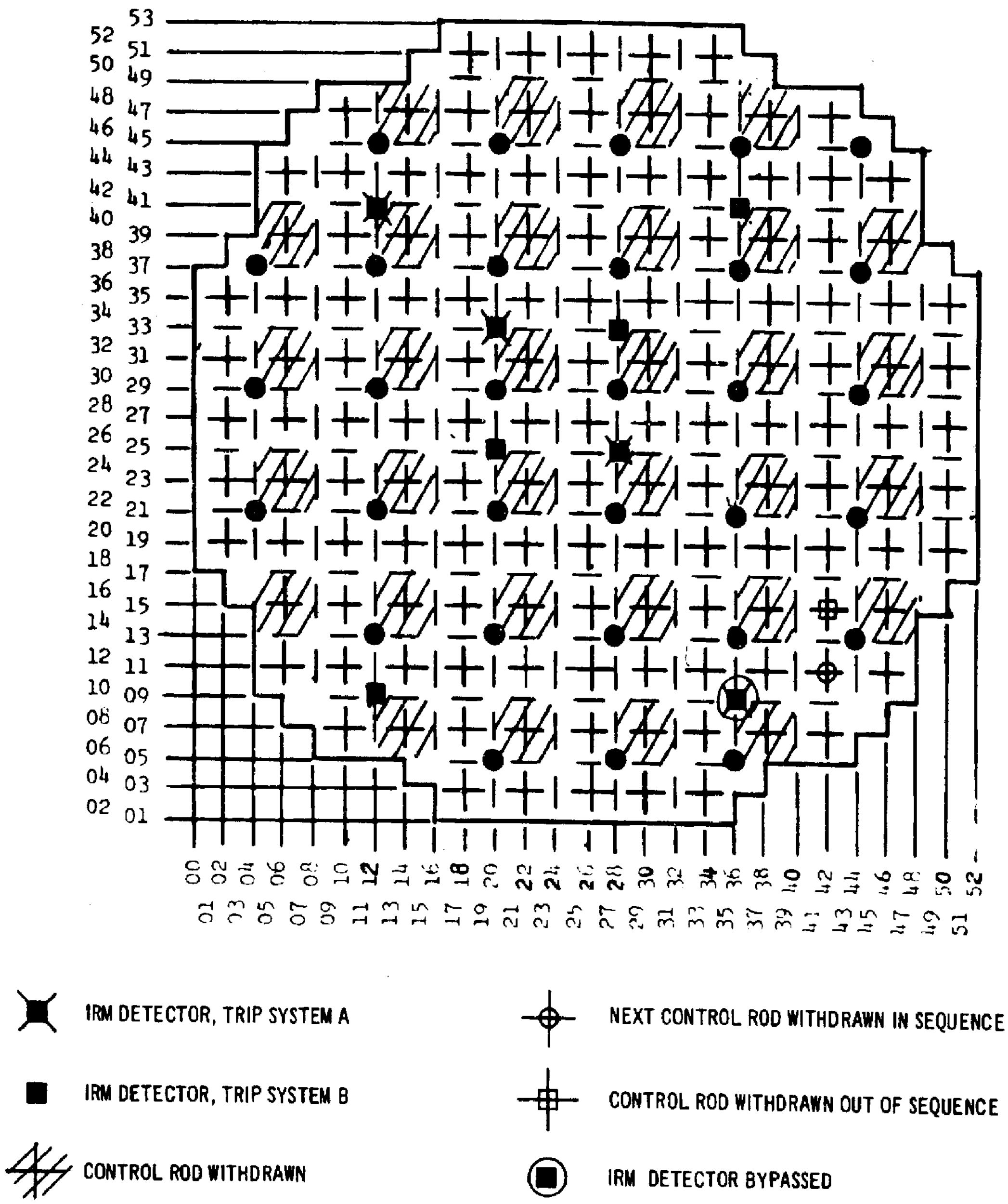
TYPICAL IRM CIRCUIT ARRANGEMENT FOR RPS INPUT

FIGURE 7.5-5



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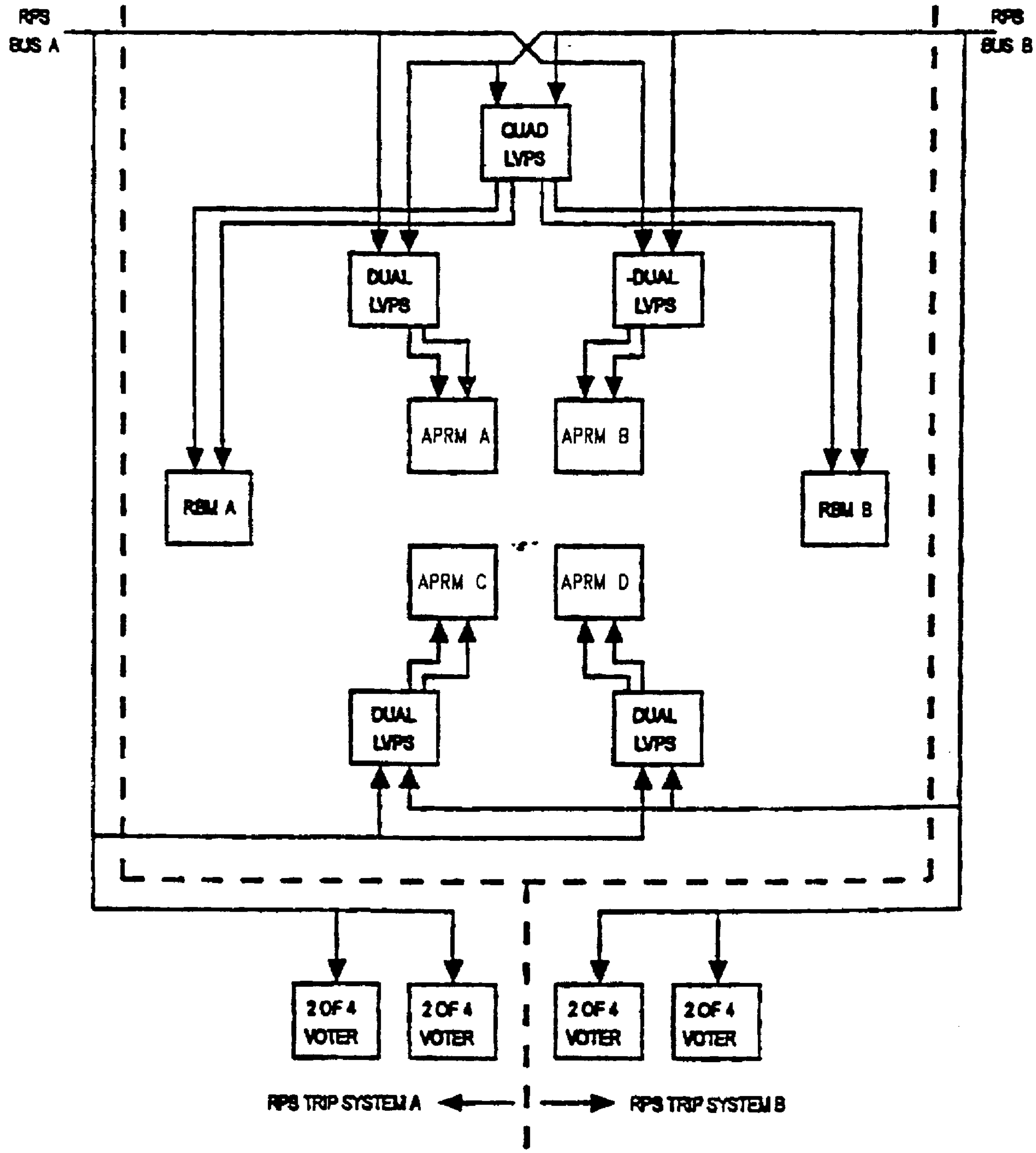
CONTROL ROD WITHDRAWAL ERROR

FIGURE 7.5-6



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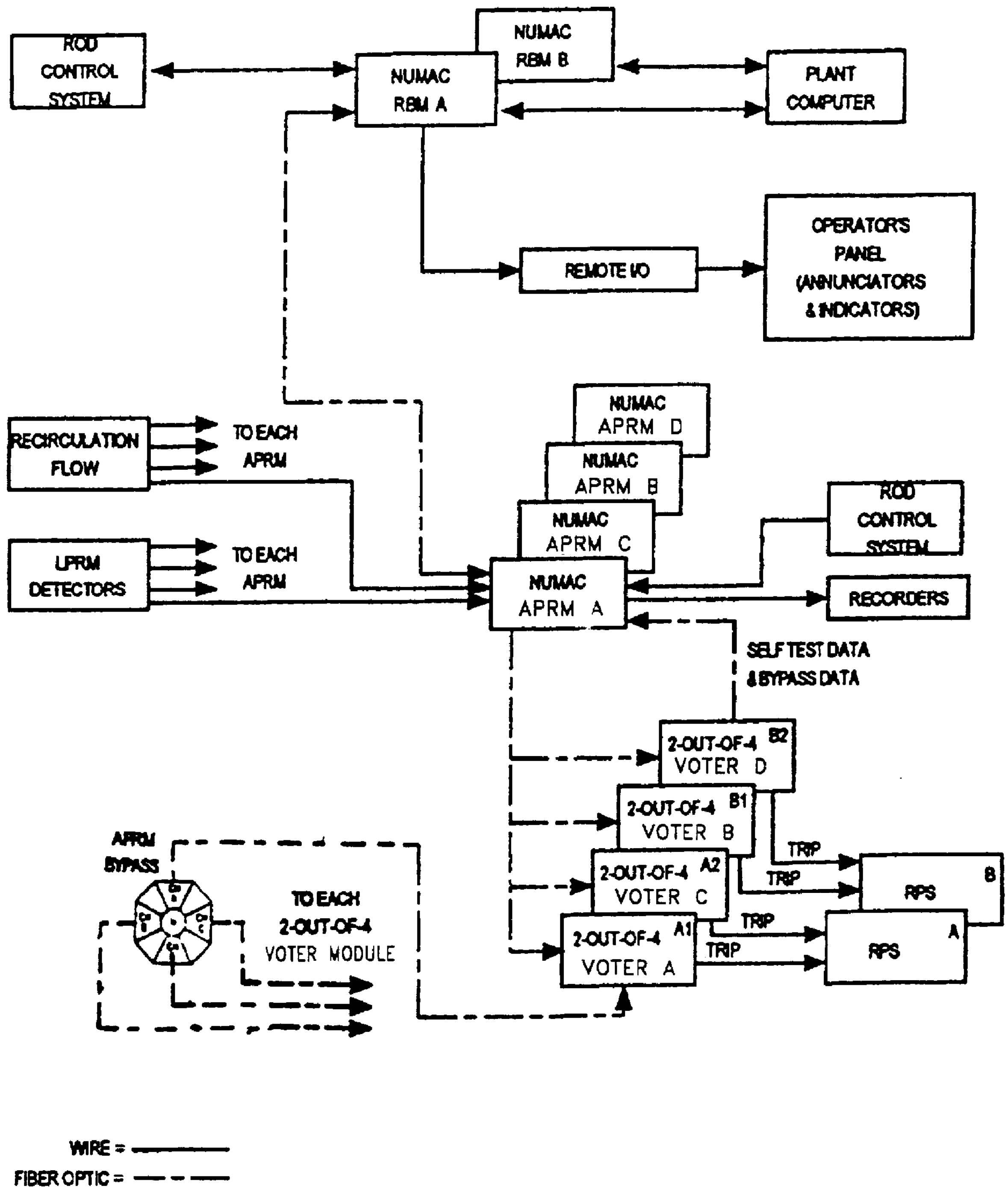
APRM/RBM POWER DISTRIBUTION INTERFACE BLOCK DIAGRAM

FIGURE 7.5-7 (SHEET 1 OF 5)



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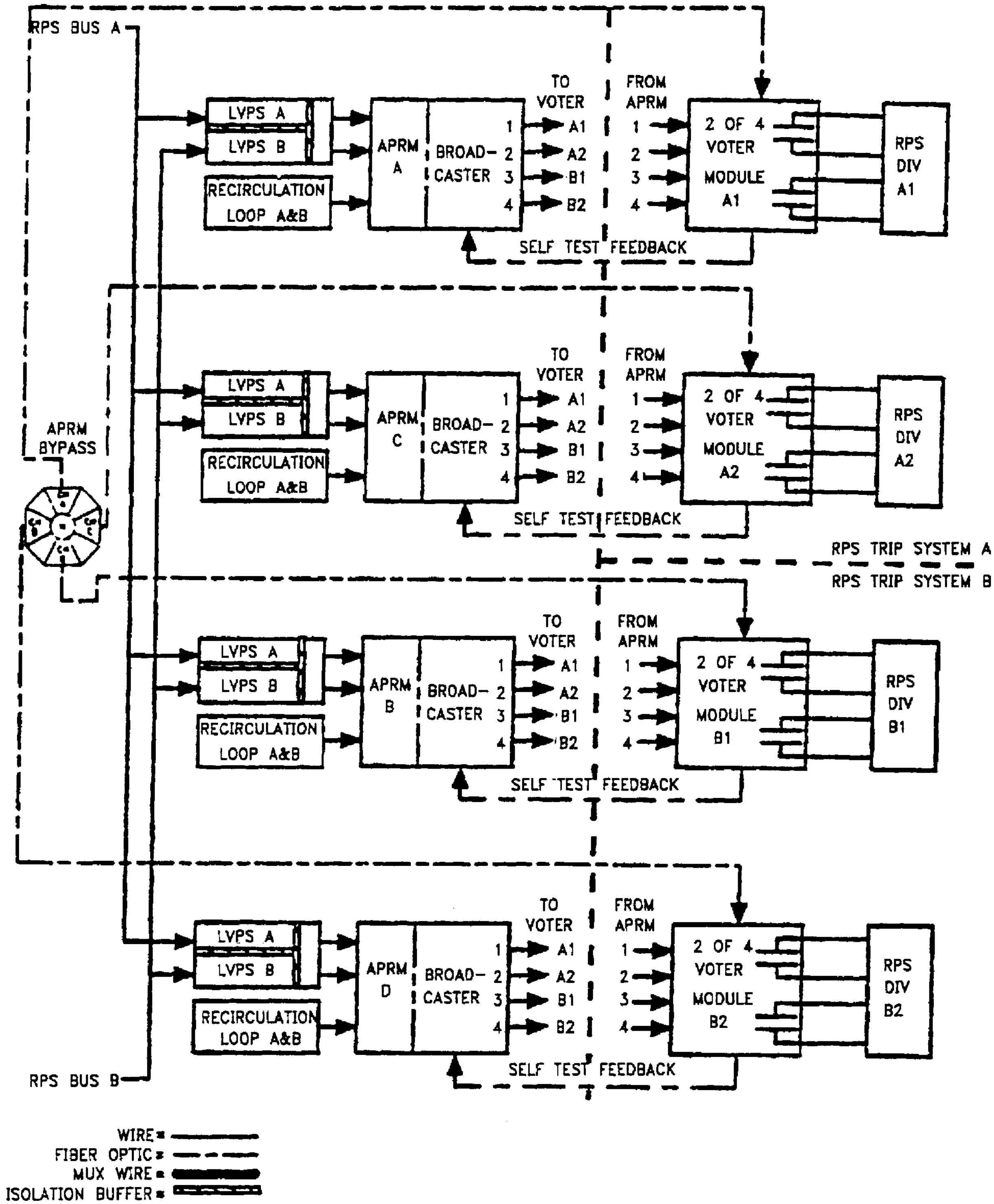
PRNM LOGIC INTERFACE BLOCK DIAGRAM

FIGURE 7.5-7 (SHEET 2 OF 5)



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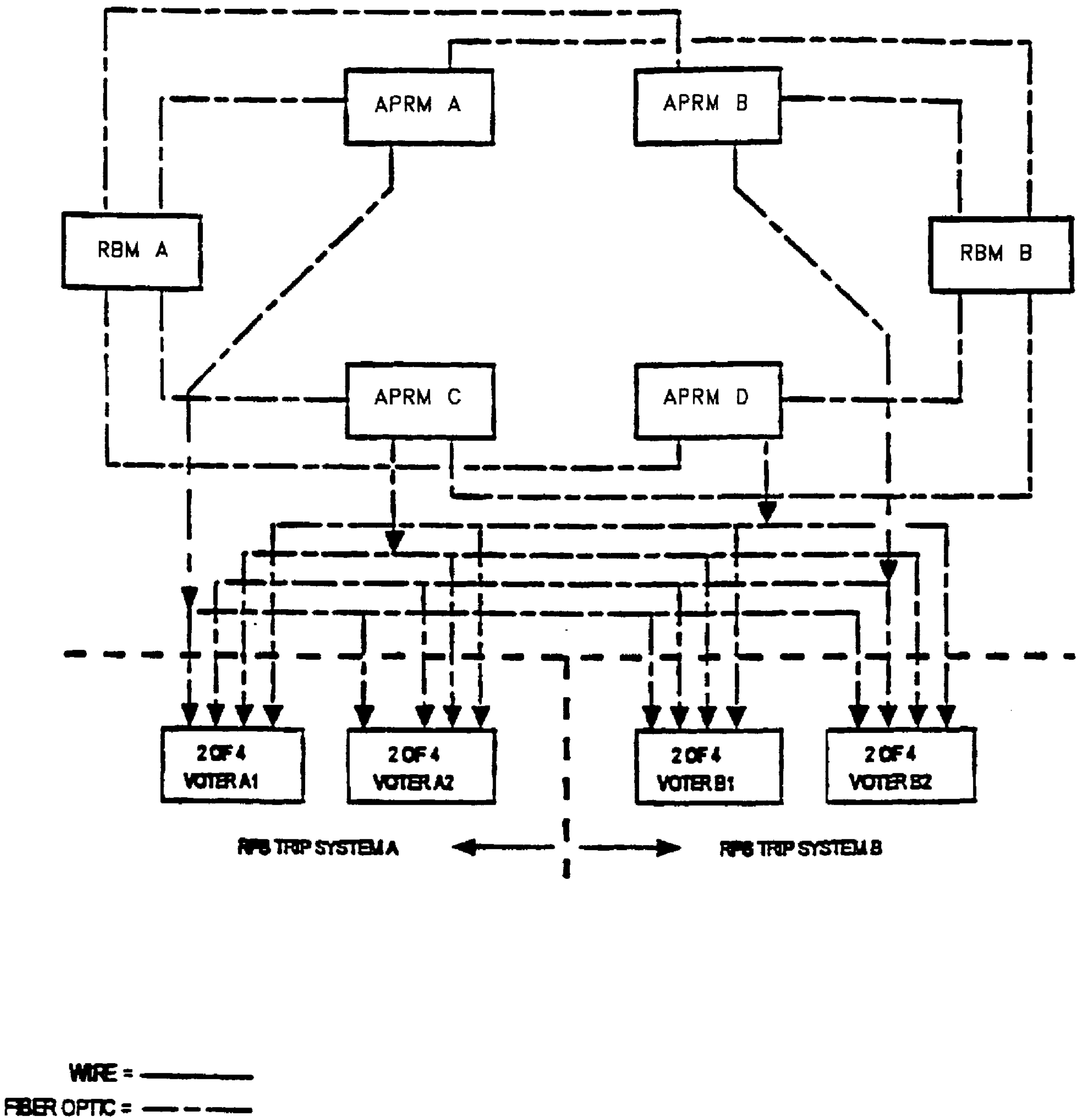
APRM/RPS INTERFACE BLOCK DIAGRAM

FIGURE 7.5-7 (SHEET 3 OF 5)



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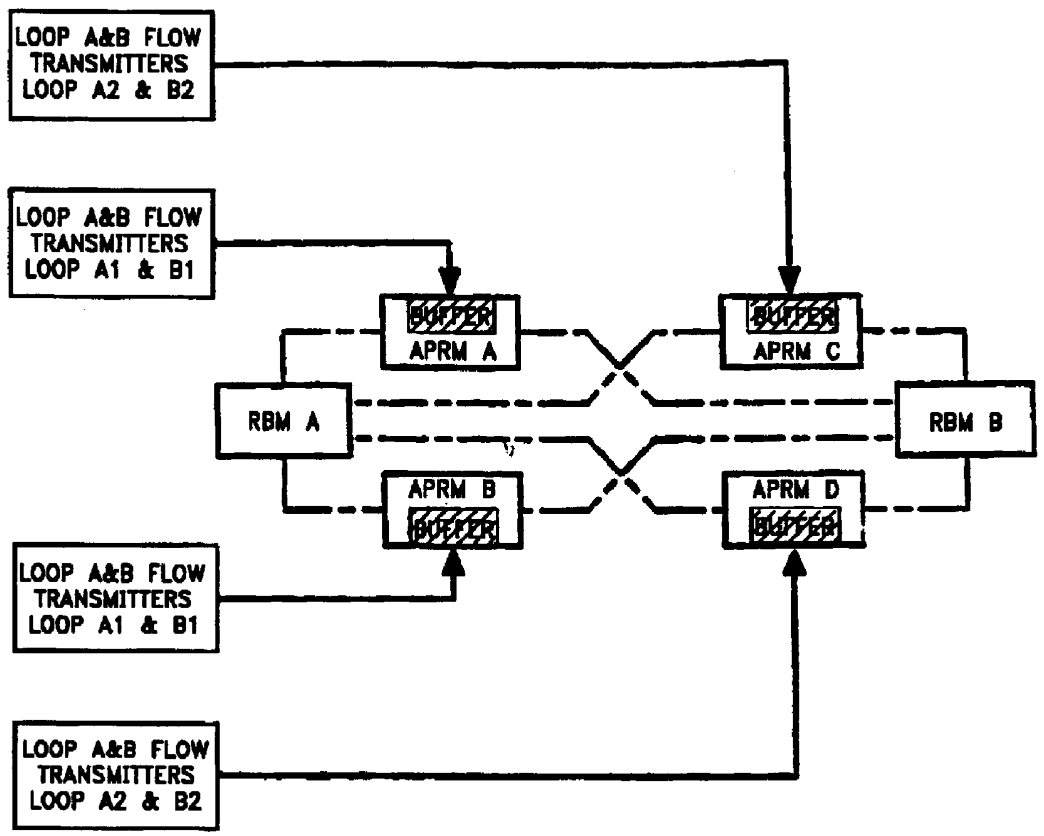
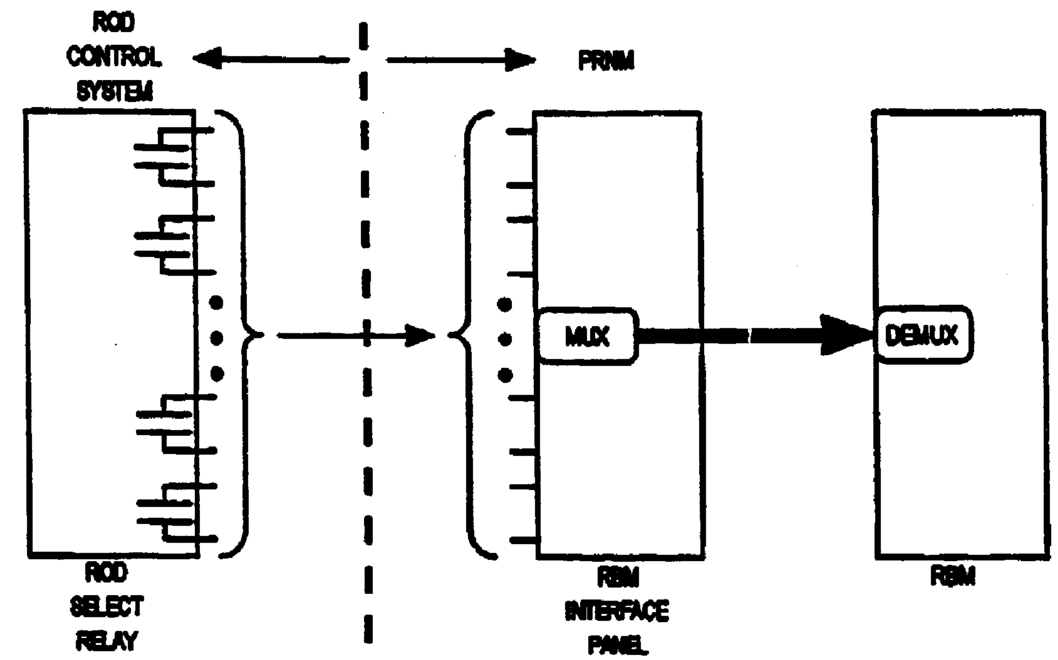
APRM/RBM CONFIGURATION BLOCK DIAGRAM

FIGURE 7.5-7 (SHEET 4 OF 5)



APRM/Flow Interface Block Diagram



RBM/Rod Control System Interface Block Diagram

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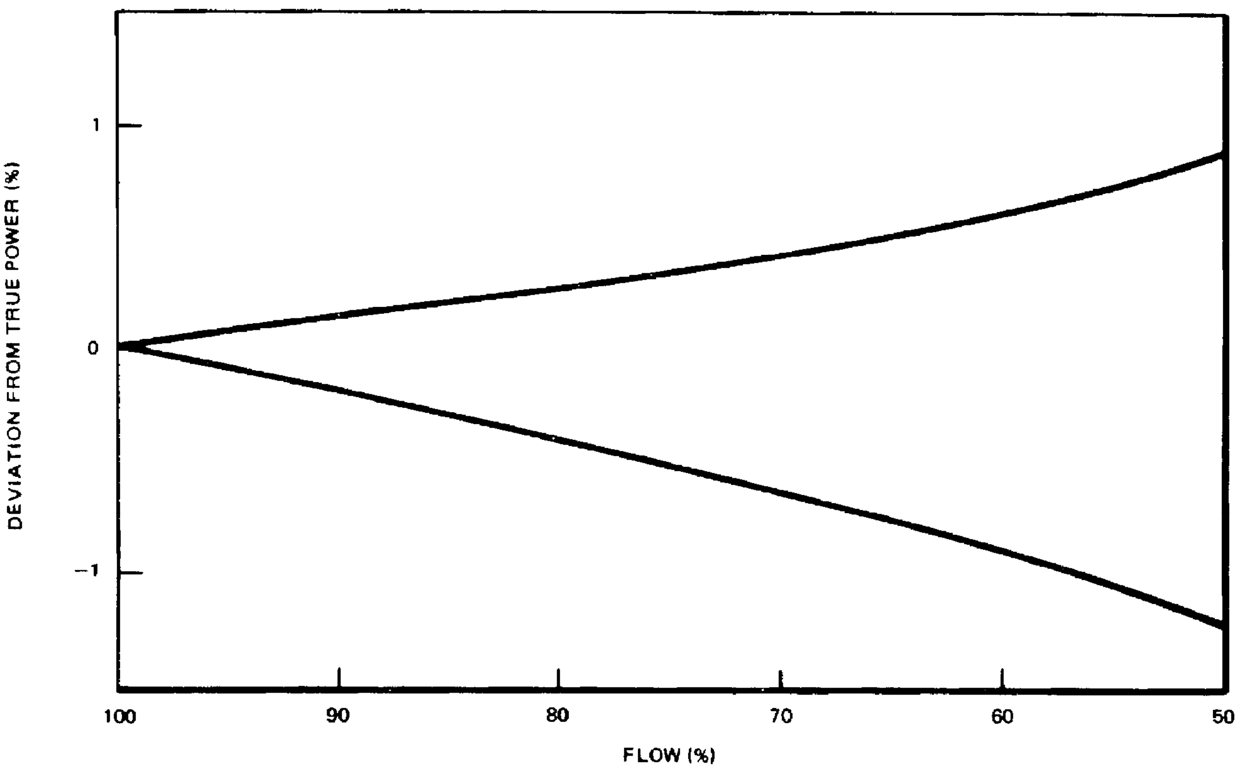
FLOW REFERENCE AND RBM INSTRUMENTATION

FIGURE 7.5-7 (SHEET 5 OF 5)



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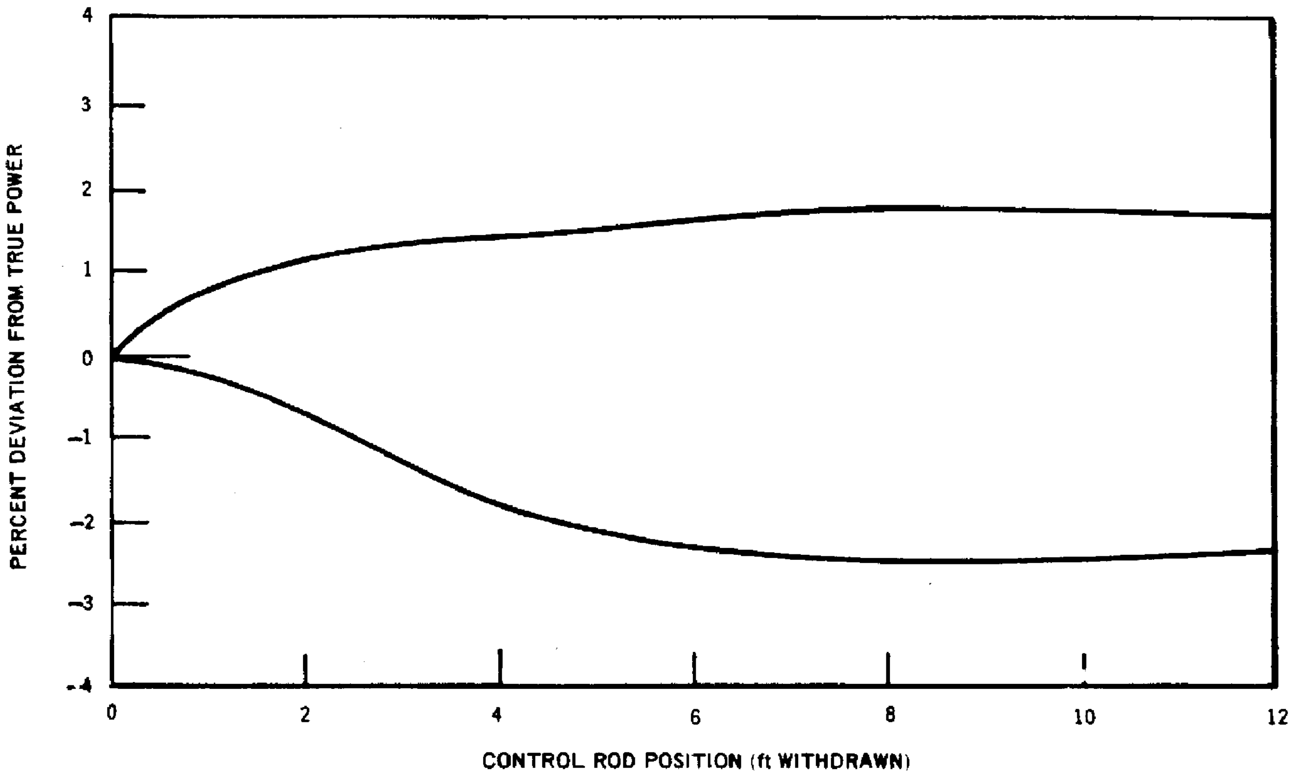
ENVELOPE OF MAXIMUM APRM DEVIATION BY FLOW CONTROL REDUCTION IN POWER

FIGURE 7.5-8



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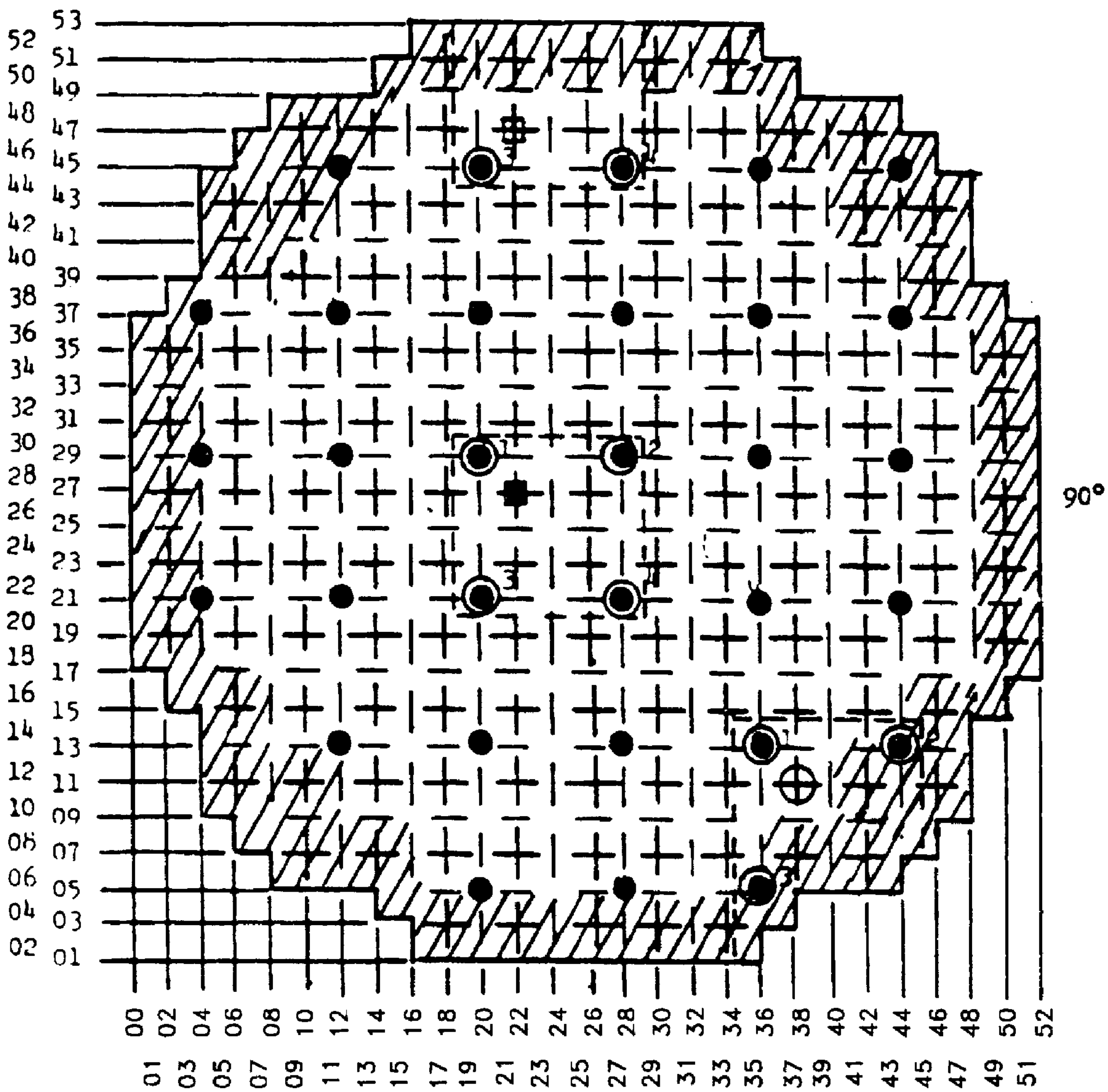
ENVELOPE OF MAXIMUM APRM DEVIATION FOR APRM TRACKING WITH ON-LIMITS CONTROL ROD WITHDRAWAL

FIGURE 7.5-9

TYPICAL
ASSIGNMENT OF LPRM INPUT TO RBM SYSTEM

NOTE: Assignment is automatically initiated upon rod selection.

CORE TOP VIEW
0°



///RBM Automatically bypassed (Reading Zeroed)

□ Typical Rod Yielding Two Power Range Detector Assemblies

○ Typical Rod Yielding Three Power Range Detector Assemblies

■ Typical Rod Yielding Four Power Range Detector Assemblies

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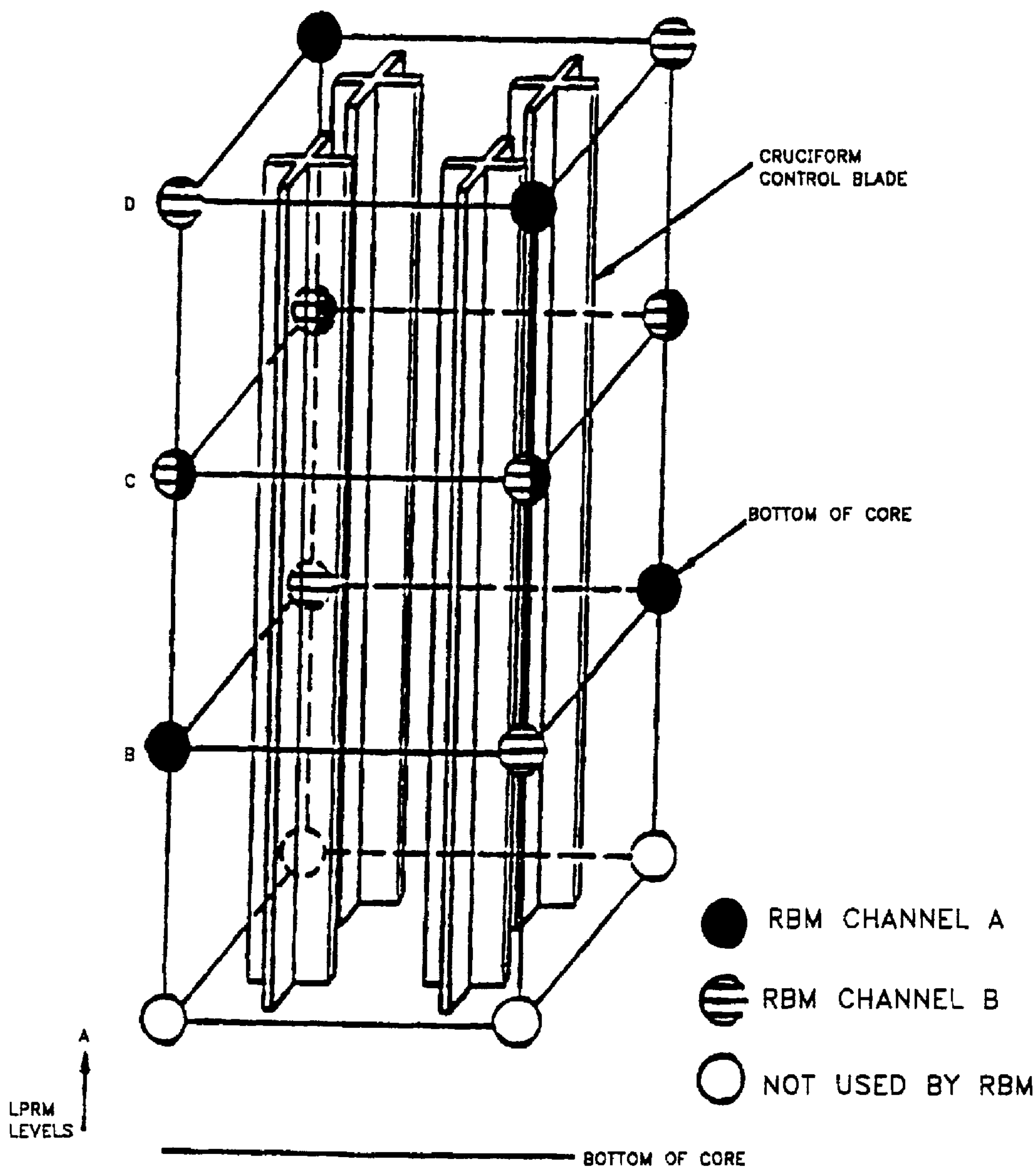
ASSIGNMENT OF POWER RANGE DETECTOR ASSEMBLIES TO RBM

FIGURE 7.5-10 (SHEET 1 OF 2)



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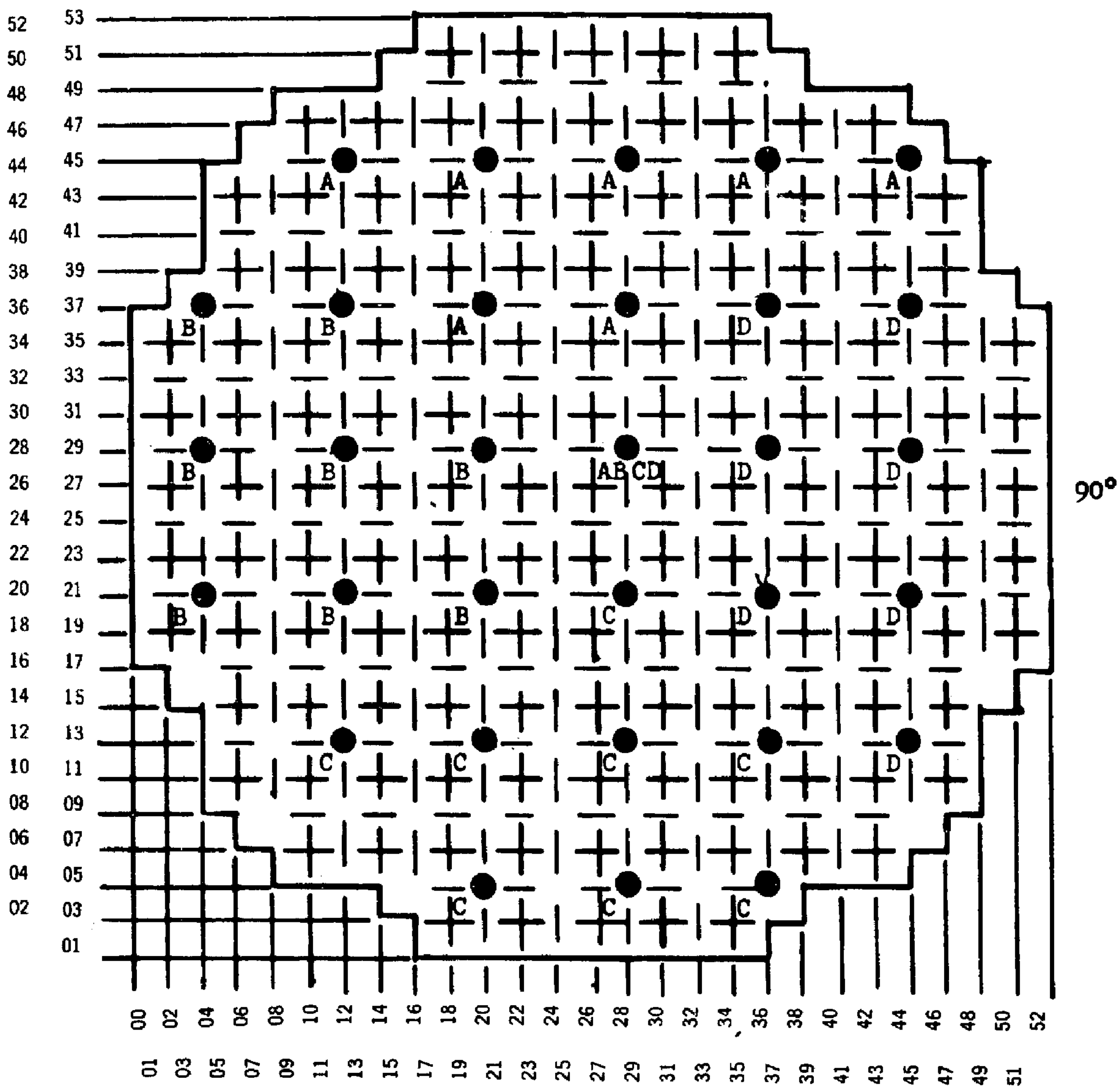
UNIT 1

LPRM TO RBM ASSIGNMENT SCHEME

FIGURE 7.5-10 (SHEET 2 OF 2)

CORE TOP VIEW
0°



LETTER = TIP MACHINE ASSIGNED TO POWER RANGE DETECTOR ASSEMBLY

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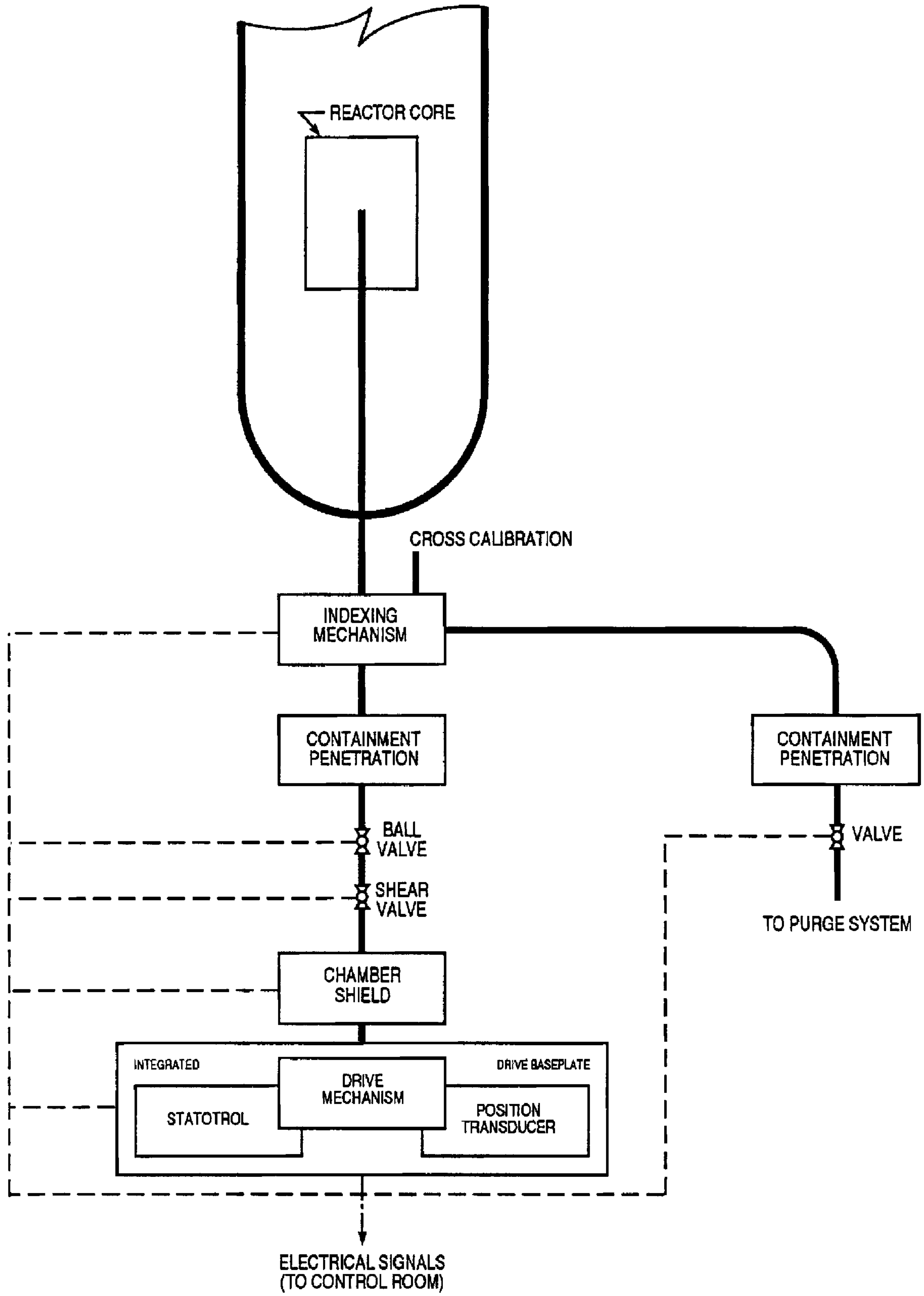
ASSIGNMENT OF LPRM STRINGS TO TIP MACHINES

FIGURE 7.5-11



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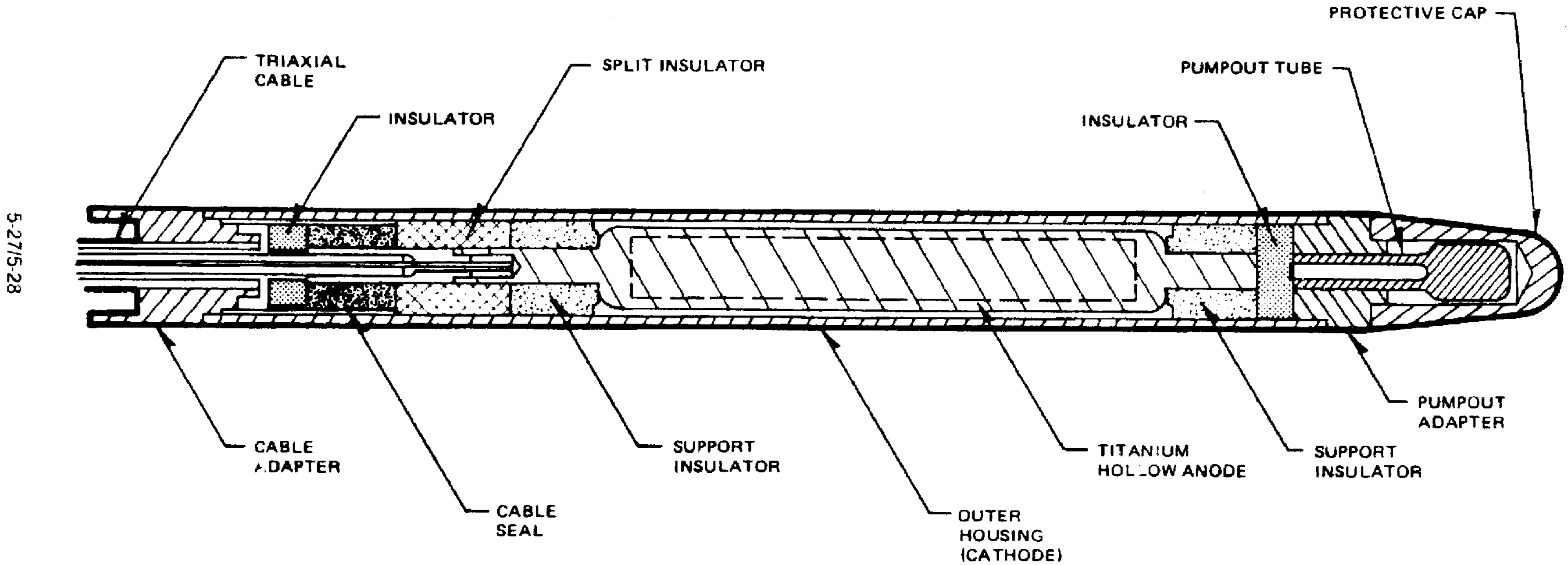
TRAVERSING INCORE PROBE SUBSYSTEM
BLOCK DIAGRAM

FIGURE 7.5-12



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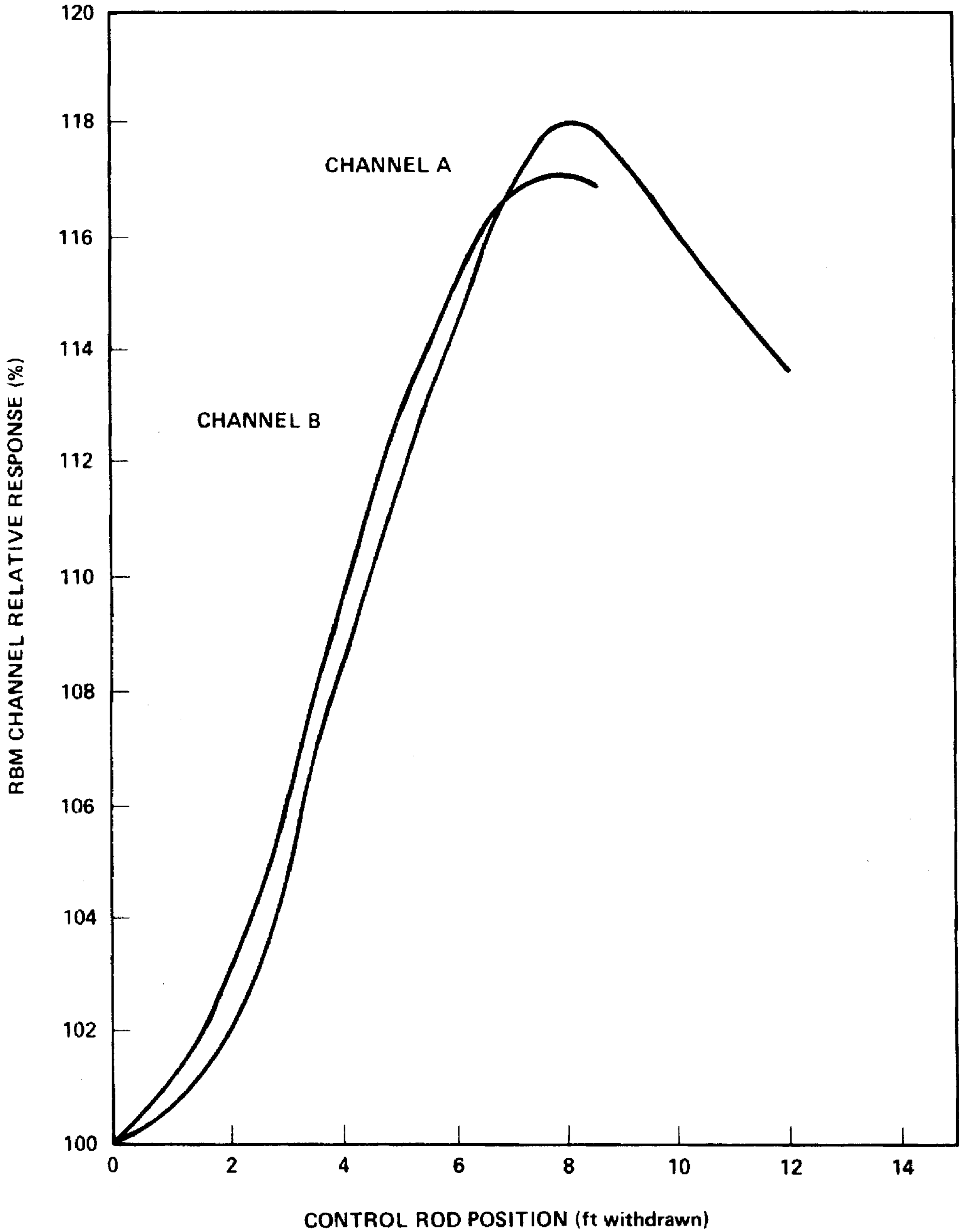
TRAVERSING INCORE PROBE ASSEMBLY

FIGURE 7.5-13



ACAD 1070514

REV 19 7/01

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UNIT 1

TYPICAL RBM CHANNEL RESPONSES
(NO FAILED LPRMs)

FIGURE 7.5-14

7.6 REFUELING INTERLOCKS

7.6.1 SAFETY OBJECTIVE

The refueling interlocks in combination with refueling procedures prevent an inadvertent criticality during refueling operations.

During a refueling operation, the reactor vessel head is removed, allowing direct access to the core. Refueling operations include the removal of reactor vessel upper internals and the movement of spent and fresh fuel assemblies between the core and the fuel storage pool. The refueling platform and the equipment handling hoists on the platform are used to accomplish the refueling task. The refueling interlocks reinforce operational procedures that prohibit taking the reactor critical under certain situations encountered during refueling operations by restricting the movement of control rods and the operation of refueling equipment.

7.6.2 SAFETY DESIGN BASES

A. During fuel movements in or over the reactor core, all control rods are in their fully inserted positions.

B. No more than one control rod is withdrawn from its fully inserted position at any time when the reactor is in the refuel mode.

7.6.3 DESCRIPTION

The refueling interlocks include circuitry which senses the condition of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated which prevent the movement of the refueling equipment or withdrawal of control rods (rod block). Circuitry is provided which senses the following conditions:

- All rods inserted.
- Refueling platform positioned near or over the core.
- Refueling platform hoists fuel loaded (fuel grapple, frame mounted hoist, trolley-mounted hoist).
- Fuel grapple not full up.
- Service platform hoist fuel loaded. (Service platform is no longer in use.)

A two-channel dc circuit indicates that all rods are in. The rod-in condition for each rod is established by the closure of a magnetically operated reed switch on the rod position indicator probe. The rod-in switch must be closed for each rod before the all-rods-in signal is generated;

two channels carry the signal. Both channels must register the all-rods-in signal in order for the refueling interlock circuitry to indicate the all-rods-in condition.

The refueling platform is provided with two mechanical switches attached to the platform which are tripped open by a long, stationary ramp mounted adjacent to the platform rail. The switches open before the platform or any of its hoists are physically located over the reactor vessel, thereby providing indication of the approach of the platform toward the core or its position over the core.

Load cell readout is accomplished by use of a solid-state load cell for the main hoist. The load cell acts as a sensor which sends a signal, which corresponds to the load on the hoist, to the indicator controller. The indicator controller receives the signal and compares it to three setpoints. The setpoints correspond to hoist loaded, hoist jammed, and slack cables. These setpoints control the operator's ability to maneuver the hoist.

The three hoists on the refueling platform are provided with switches which open when the hoists are fuel loaded. The switches are set to open at a load weight which is lighter than the weight of a single fuel assembly, thus providing positive indication whenever fuel is loaded on any hoist.

The telescoping fuel grapple hoist is provided with a limit switch which is open any time the grapple has descended more than ~ 4 in. from its full-up position. This switch is placed in series with the grapple load switch to ensure interlock operation in the event that the weight of the bottom section of the telescope plus the fuel is less than the preset load.

The indicated conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operation and control rod movement, as described on drawing nos. H-19918 through H-19925 and H-19967, and in the following:

A. Refueling platform travel toward the core is stopped when the following three conditions exist concurrently:

- Any refueling platform hoist is loaded or the fuel grapple is not in its full-up position.
- Not all rods in.
- Refueling platform position is such that the position switch is open (platform near or over the core).

B. With the mode switch in STARTUP, refueling platform travel toward the core is prevented when the refueling platform position switch is open (platform near or over the core).

C. With the mode switch in REFUEL, refueling platform travel towards the core is prevented when the following two conditions exist concurrently:

- More than one rod withdrawn.

- The refueling platform position switch is open (platform near or over the core).

D. The refueling platform frame-mounted hoist LIFT electrical circuit is open when the following three conditions exist concurrently:

- Frame-mounted hoist fuel loaded.

- Not all rods in.

- Refueling platform near or over the core.

E. The refueling platform trolley-mounted hoist LIFT electrical circuit is open when the following three conditions exist concurrently:

- Trolley-mounted hoist fuel loaded.

- Not all rods in.

- Refueling platform near or over the core.

F. Operation of the telescoping fuel grapple is prevented when the following two conditions exist concurrently:

- Not all rods in.

- Refueling platform near or over the core.

G. With the mode switch in REFUEL, either of the following conditions prevents a control rod withdrawal:

- Refueling platform over the core with a load on any refueling platform hoist or the fuel grapple not fully up.

- Selection of a second rod for movement with any other rod withdrawn from the fully inserted position.

H. With the mode switch in STARTUP, the following condition prevents a control rod withdrawal:

- Refueling platform over the core.

The prevention of a control rod withdrawal is accomplished by opening contacts at two different points in the rod block circuitry; prevention of refueling equipment operation is accomplished by interrupting the power supply to the equipment.

During refueling operations, no more than one control rod may be withdrawn; this is enforced by a redundant logic circuit which uses the all-rods-in signal and a rod selection signal to prevent the selection of a second rod for movement with any other rod not fully inserted. The simultaneous selection of two control rods is prevented by the interconnection arrangement of the select pushbuttons. With the mode switch in REFUEL, the circuitry prevents the withdrawal of more than one control rod and the movement of the loaded refueling platform over the core with any control rod withdrawn.

Circuitry is provided to interact with a service platform which is no longer available. A bypass plug allows control rod movement logic to operate correctly in absence of the service platform.

7.6.4 SAFETY EVALUATION

The refueling interlocks, in combination with core nuclear design and refueling procedures, limit the probability of an inadvertent criticality. The nuclear characteristics of the core assure that the reactor is subcritical even when the highest worth control rod is fully withdrawn. Refueling procedures are written to avoid situations in which inadvertent criticality is possible. The combination of refueling interlocks for control rods and the refueling platform provides redundant methods of preventing inadvertent criticality even after procedural violations. The interlocks on hoists provide yet another method of avoiding inadvertent criticality.

Table 7.6-1 illustrates the effectiveness of the refueling interlocks. This table considers various operational situations involving rod movement, hoist load conditions, refueling platform movement and position, and mode switch manipulation. The initial conditions in situations 4 and 5 appear to be in contradiction to the action of refueling interlocks, because the initial conditions indicate that more than one control rod is withdrawn, yet the mode switch is in REFUEL. Such initial conditions are possible if the rods are withdrawn when the mode switch is in STARTUP, and then the mode switch is turned to REFUEL. The scram indicated in situation 17 of table 7.6-1 is not a result of the refueling interlocks; it is the response of the reactor protection system to having three or more main steam lines with an isolation valve < 90% open when the mode switch is shifted to the RUN position. (When the switch is put into the RUN mode, the main steam pressure must be maintained above 825 psig in order to keep the main steam isolation valves open. During refueling, reactor and steam pressure are at atmospheric, and the valves are already closed.) In all cases, proper operation of the refueling interlock is successful in preventing either the operation of loaded refueling equipment over the core whenever any control rod is withdrawn or the withdrawal of any control rod when fuel-loaded refueling equipment is operating over the core. In addition, when the mode switch is in REFUEL, only one rod can be withdrawn; selection of a second rod initiates a rod block.

7.6.5 INSPECTION AND TESTING

Complete functional testing of all refueling interlocks before any refueling outage provides positive indication that the interlocks operate in the situations for which they were designed. By loading each hoist with a dummy fuel assembly or appropriate test weight, positioning the refueling platform, and withdrawing control rods (or simulating withdrawal), the interlocks can be subjected to valid operational tests. Where redundancy is provided in the logic circuitry, tests can be performed to assure that each redundant logic element can independently perform its function.

TABLE 7.6-1 (SHEET 1 OF 2)

REFUELING INTERLOCK EFFECTIVENESS

Situation	Refueling Platform Position	Refueling TMH	Platform FMH	Hoists FG	Control Rods	Mode Switch	Attempt	Result
1	Not near core	UL	UL	UL	All rods in	Refuel	Move refueling platform over core	No restrictions
2	Not near core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
3	Not near core	UL	UL	UL	One rod	Refuel	Move refueling platform over core	No restrictions
4	Not near core	Any hoist loaded or FG not fully up			One or more rods withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
5	Not near core	UL	UL	UL	More than one rod withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
6	Over core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
7	Over core	Any hoist loaded or FG not fully up			All rods in	Refuel	Withdraw rods	Rod block
8	Not near core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Rod block
9	Not near core	UL	UL	UL	All rods in	Refuel	Operate platform hoist	No restrictions
10*								
11	Not near core	UL	UL	UL	All rods in	Startup	Move refueling platform over core	Platform stopped before over core

TABLE 7.6-1 (SHEET 2 OF 2)

Situation	Refueling Platform Position	Refueling TMH	Platform FMH	Hoists FG	Control Rods	Mode Switch	Attempt	Result
12*								
13*								
14	Not near core	UL	UL	UL	All rods in	STARTUP	Withdraw rods	Rod block
15	Not near core	UL	UL	UL	All rods in	STARTUP	Withdraw rods	No restrictions
16	Over core	UL	UL	UL	All rods in	STARTUP	Withdraw rods	Rod block
17	Any		Any condition		Any condition, reactor pressure < 825 psig	STARTUP	Turn mode switch to RUN	Scram

LEGEND:

TMH - trolley mounted hoist; FMH - frame mounted hoist; FG - fuel grapple; UL - unloaded; L - fuel loaded
* - Situations 10, 12, and 13 do not exist because the reactor vessel service platform has been removed.

7.7 REACTOR MANUAL CONTROL SYSTEM

7.7.1 POWER GENERATION OBJECTIVE

The objective of the reactor manual control system (RMCS) is to provide the operator with the means to make changes in nuclear reactivity so that the reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

7.7.2 SAFETY DESIGN BASES

A. The circuitry provided for the manipulation of control rods is designed so that no single failure can negate the effectiveness of a reactor protection system action (scram).

B. Repair, replacement, or adjustment of any failed or malfunctioning component requires that any element needed for scram be bypassed unless a bypass is normally allowed.

7.7.3 POWER GENERATION DESIGN BASES

A. The RMCS is designed to inhibit control rod withdrawal following erroneous control rod manipulations so that scram is not required.

B. The RMCS is designed to inhibit control rod withdrawal in time to prevent local fuel damage as a result of erroneous control rod manipulation.

C. The RMCS is designed to inhibit rod movement whenever such movement would result in operationally undesirable core reactivity conditions or whenever instrumentation (due to failure) is incapable of monitoring the core response to rod movement.

D. To limit the potential for inadvertent rod withdrawals leading to scram, the RMCS is designed in such a way that deliberate operator action is required to effect a continuous rod withdrawal.

E. To provide the operator with the means to achieve prescribed control rod patterns, information pertinent to the position and motion of the control rods is available in the main control room (MCR).

7.7.4 DESCRIPTION

7.7.4.1 Identification

The RMCS consists of the electrical circuitry, switches, indicators, and alarm devices provided for operational manipulation of the control rods and the surveillance of associated equipment. This system includes the interlocks that inhibit rod movement (rod block) under certain conditions. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor. These devices are discussed in section 7.2, Reactor Protection System. Neither are the mechanical devices of the control rod drives (CRDs) nor the CRD hydraulic system included in the RMCS. These mechanical components are described in HNP-2-FSAR subsection 4.2.3, Reactivity Control System.

7.7.4.2 Operation

7.7.4.2.1 General

HNP-2-FSAR figure 4.2-14 (sheet 1 of 2) shows the functional arrangement of devices for the control of components in the CRD hydraulic system. Although the figure shows the arrangement of scram devices, these devices are not part of the RMCS.

Control rod movement is accomplished by admitting water under pressure from a CRD water pump into the appropriate end of the CRD cylinder. The pressurized water forces the piston, which is attached by a connecting rod to the control rod, to move. Three modes of control rod operation are used: insert, withdraw, and settle. Four solenoid-operated valves are associated with each control rod to accomplish the actions required for the various operational modes. The valves control the path that the CRD water takes to the cylinder. The RMCS controls the valves.

Two of the four solenoid-operated valves for a control rod are electrically connected to the insert bus. When the insert bus is energized and when a control rod has been selected for movement, the two insert valves for the selected rod open allowing the CRD water to take the path that results in control rod insertion. Of the two remaining solenoid-operated valves for a control rod, one is electrically connected to the withdraw bus, and the other is connected to the settle bus. The withdraw valve that connects the insert drive water supply line to the exhaust water heater is one that is connected to the settle bus. The remaining withdraw valve is connected to the withdraw bus. When both the withdraw bus and the settle bus are energized and when a control rod has been selected for movement, both withdraw valves for the selected rod open allowing CRD water to take the path that results in control rod withdrawal.

The settle mode is provided to ensure the CRD index tube is engaged promptly by the collet fingers after the completion of either an insert or withdraw cycle. During the settle mode, the withdraw valve connected to the settle bus is opened or remains open while the other three solenoid-operated valves are closed. During an insert cycle, the settle action vents the pressure from the bottom of the CRD piston to the exhaust header, thus gradually reducing the differential pressure across the drive piston of the selected rod. During a withdraw cycle, the settle action again vents the bottom of the CRD piston to the exhaust header while the withdraw drive water supply is shut off. This also allows a gradual reduction in the differential pressure across the CRD piston. After the control rod has slowed down, the collet fingers engage the index tube and lock the rod in position. See drawing no. H-19918 for valve sequence and timing.

The arrangement of control rod selection pushbuttons and circuitry permits the selection of only one control rod at a time for movement. A rod is selected for movement by depressing a button for the desired rod on the reactor control bench board in the control room. The direction in which the selected rod moves is determined by the position of the rod movement switch which is also located on the reactor control bench board. This switch has rod-in and rod-out-notch positions and returns by spring action to the "off" position. The rod selection circuitry is arranged so that a rod selection is sustained until either another rod is selected or separate action is taken to revert the selection circuitry to a no-rod-selected condition. Initiating movement of the selected rod prevents the selection of any other rod until the movement cycle of the selected rod has been completed. Reversion to the no-rod-selected condition is not possible (except for loss of control circuit power) until any moving rod has completed the movement cycle.

7.7.4.2.2 Insert Cycle

The following is a description of the detailed operation of the RMCS during an insert cycle. The cycle is described in terms of the insert, withdraw, and settle buses. The response of a selected rod when the various buses are energized has been explained previously. Drawing nos. H-19920 and H-19921 can be used to follow the sequence of an insert cycle.

A three-position rod movement switch is provided on the reactor control bench board. The switch has rod-in, rod-out-notch, and "off" positions. The switch returns by spring action to the "off" position. With a control rod selected for movement, placing the rod movement switch in the rod-in position and then releasing the switch energizes the insert bus for a limited amount of time. Just before the insert bus is deenergized, the settle bus is automatically energized and remains energized for a limited period of time after the insert bus is deenergized. The insert bus time setting and rate of drive water flow provided by the CRD hydraulic system determines the distance traveled by a rod. The timer setting results in a one-notch (6 in.) insertion of the selected rod for each momentary application of a rod-in signal from the rod movement switch. Continuous insertion of a selected control rod is possible by holding the rod movement switch in the rod-in position.

A second switch can be used to initiate insertion of a selected control rod. This switch is the rod-out-notch-override (RONOR) switch. The RONOR switch has three positions: emergency-in, notch-override, and "off." The switch returns to the "off" position by spring action. By holding the RONOR switch in the emergency-in position, the insert bus is continuously energized causing a continuous insertion of the selected control rod.

7.7.4.2.3 Withdraw Cycle

The following is a description of the detailed operation of the RMCS during a withdraw cycle. The cycle is described in terms of the insert, withdraw, and settle buses. The response of a selected rod when the various buses are energized has been explained previously. Drawing nos. H-19920 and H-19921 can be used to follow the sequence of a withdraw cycle.

With a control rod selected for movement, placing the rod movement switch in the rod-out-notch position energizes the insert bus for a short period of time. Energizing the insert bus at the beginning of the withdrawal cycle is necessary to allow the collect fingers to disengage the index tube. When the insert bus is deenergized, the withdraw and settle buses are energized for a controlled period of time. The withdraw bus is deenergized prior to the settle bus which, when deenergized, completes the withdraw cycle. This withdraw cycle is the same whether the rod movement switch is held continuously in the rod-out-notch position or released. The timers that control the withdraw cycle are set so that the rod travels one notch (6 in.) per cycle. (Provisions are included to prevent further control rod motion in the event of timer failure.) A selected control rod can be continuously withdrawn if the rod movement switch is held in the rod-out-notch position at the same time the RONOR switch is held in the notch-override position. With both switches held in these positions, the withdraw bus is continuously energized.

7.7.4.2.4 Control Rod Drive Hydraulic System Control

Two motor-operated pressure control valves, one air-operated flow-control valve, and two solenoid-operated stabilizing valves are included in the CRD hydraulic system to maintain smooth and regulated system operation. (See HNP-2-FSAR subsection 4.2.3, Reactivity Control System.) The motor-operated pressure-control valves are positioned by manipulating switches in the control room. The switches for these valves are located close to the pressure indicators that respond to the pressure changes caused by movements of the valves. The air-operated flow-control valve is automatically positioned in response to signals from an upstream flow measuring device. The stabilizing valves are automatically controlled by the action of the energized insert and withdraw buses. The control scheme is shown on drawing nos. H-19919 through H-19922. The two drive water pumps are controlled by switches in the MCR. Each pump automatically stops upon indication of low-suction pressure (drawing no. H-19918).

7.7.4.3 <u>Rod Block Interlocks</u>

7.7.4.3.1 General

Drawing nos. H-19920 through H-19922 show the rod block interlocks used in the RMCS. Drawing nos. H-19920 and H-19921 show the general functional arrangement of the interlocks; and drawing no. H-19919 shows the rod blocking functions that originate in the neutron monitoring system in greater detail.

To achieve an operationally desirable performance objective where most failures of individual components would be easily detectable or do not disable the rod movement inhibiting functions, the rod block logic circuitry is arranged as two similar logic circuits. The two logic circuits are energized when control rod movement is allowed. Each logic circuit receives input trip signals from a number of trip channels, and each logic circuit can provide a separate rod block signal to inhibit rod withdrawal.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even if a continuous rod withdrawal is in progress.

The components used to initiate rod blocks in combination with refueling operations provide rod block trip signals to these same rod block circuits. These refueling rod blocks are described in section 7.6, Refueling Interlocks.

7.7.4.3.2 Rod Block Functions

The following discussion describes the various rod block functions and explains the intent of each function. The instruments used to sense the conditions for which a rod block is provided are discussed later. Drawing nos. H-19919 and H-19931 show the rod block initiation functions. Drawing nos. H-19928 and H-19932 show the rod block functions initiated in the neutron monitoring system. The channels A and B annunciating rod block and nonannunciating rod block controls on drawing no. H-19920 initiate rod blocks in the RMCS, as indicated on drawing nos. H-19919 and H-19920. The rod block functions provided specifically for refueling situations are described in section 7.6, Refueling Interlocks. Following is a discussion of the rod block functions and their circuitry. The operability requirements of these functions are specified in the Technical Specifications and the Technical Requirements Manual.

A. With the mode switch in the SHUTDOWN position, no control rod can be withdrawn. This enforces compliance with the intent of the shutdown mode.

B. The circuitry is arranged to initiate a rod block regardless of the position of the mode switch for the following conditions:

   1. <u>Any Average Power Range Monitor (APRM) Upscale Rod Block Alarm</u>. The purpose of this rod block function is to avoid conditions that would require scram if allowed to proceed. The APRM upscale rod block alarm setting is selected to initiate a rod block before the APRM high neutron flux scram setting is reached.

   2. <u>Any APRM Inoperative Alarm</u>. This assures no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or properly bypassed.

3. Either Rod Block Monitor (RBM) Upscale Alarm. This function is provided to stop the erroneous withdrawal of a single worst-case control rod so that violation of the fuel-cladding integrity safety limit does not result. Although such violation poses no significant threat in terms of radioactive material released from the nuclear system, the alarm setting is selected so that no violation of the fuel-cladding integrity safety limit results from a single control rod withdrawal error during power range operation.

4. Either RBM Inoperative Alarm. This assures that no control rod is withdrawn unless the RBM channels are in service or properly bypassed.

5. Scram Discharge Volume High Water Level. This assures that no control rod is withdrawn unless enough capacity is available in the scram discharge volume to accommodate a scram. The setting is selected to initiate a rod block well in advance of that level which produces a scram.

6. Scram Discharge Volume High Level Scram Trip Bypassed. This assures that no control rod is withdrawn while the scram discharge volume high water level scram function is out of service.

7. Rod Worth Minimizer (RWM). The RWM can initiate rod insert and rod withdrawal blocks. The purpose of this function is to reinforce procedural controls that limit the reactivity worth of control rods under low-power conditions. The rod block trip settings are based on the allowable control rod worth limits established for the design basis rod drop accident. Adherence to prescribed control rod patterns is the normal method by which this reactivity is observed. Additional information on the RWM is available in HNP-2-FSAR section 7.10, Rod Worth Minimizer.

8. Rod Position Information System Malfunction. This assures no control rod can be withdrawn unless the rod position information system is in service.

9. Rod Movement Timer Switch Malfunction During Withdrawal. This assures no control rod can be withdrawn unless the timer is in service.

C. With the mode switch in the RUN position, the following conditions initiate a rod block:

1. Any APRM Downscale Alarm. This assures no control rod is withdrawn during the power range operation unless the average power range neutron monitoring channels are operating properly or are correctly bypassed. All unbypassed APRMs must be onscale during reactor operation in the RUN mode.

2. Either RBM Downscale Alarm. This assures no control rod is withdrawn during power range operation unless the RBM channels are operating properly or are correctly bypassed. Unbypassed RBM must be onscale

during reactor operations in the RUN mode. The RBMs are automatically bypassed when reactor power is < 30%.

D. With the mode switch in STARTUP or REFUEL position, the following conditions initiate a rod block:

1. Any Source Range Monitor (SRM) Detector Not Fully Inserted Into Core When SRM Count Level Is Below Retract Permit Level and any Intermediate Range Monitor (IRM) Range Switch on Either of Two Lowest Ranges. This assures no control rod is withdrawn unless all SRM detectors are properly inserted when they must be relied upon to provide the operator with neutron flux level information. There are certain periods of time during an outage where the rod block for “Detector Not Fully Inserted” will be disabled. This exception is addressed in Technical Requirements Manual (TRM) 3.3.2-1, Item 1.a, and involves compensatory actions that will be in place to ensure that the SRM detector remains fully inserted in the core.

2. Any SRM Upscale Level Alarm. This assures no control rod is withdrawn unless the SRM detectors are properly retracted during a reactor startup. The rod block setting is selected at the upper end of the range over which the SRM is designed to detect and measure neutron flux.

3. Any SRM Downscale Alarm. This assures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring.

4. Any SRM Inoperative Alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all SRM channels are in service or properly bypassed.

5. Any IRM Detector Not Fully Inserted Into Core. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all IRM detectors are properly located. There are certain periods of time during an outage where the rod block for “Detector Not Fully Inserted” will be disabled. This exception is addressed in Technical Requirements Manual (TRM) 3.3.2-1, Item 2.a, and involves compensatory actions that will be in place to ensure that the IRMs remain fully inserted in the core. The IRMs provide reactivity monitoring during Mode 5 and protect against unexpected reactivity excursions by initiating a reactor high neutron flux scram. This function will not be affected during these periods of time where exception is taken to this rod block function.

6. Any IRM Upscale Alarm. This assures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is properly upranged during a reactor startup. This rod block also provides a means to

stop rod withdrawal in time to avoid conditions requiring scram in the event that a rod withdrawal error is made during low neutron flux level operations.

7. Any IRM Downscale Alarm Except When Range Switch Is on Lowest Range. This assures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being properly monitored. This rod block prevents the continuation of a reactor startup if the operator upranges the IRM too far for the existing flux level, thus the rod block ensures that the IRM is onscale if control rods are to be withdrawn.

8. Any IRM Inoperative Alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all IRM channels are in service or properly bypassed.

7.7.4.3.3 Rod Block Bypasses

To permit continued power operation during the repair or calibration of equipment for selected functions which provide rod block interlocks, a limited number of manual bypasses are permitted as follows:

- One SRM channel.
- Two IRM channels (one on either bus A or bus B).
- One APRM channel.
- One RBM channel.

The IRM bypasses are arranged as two groups of equal numbers of channels. One manual bypass is allowed in each group. The groups are chosen so that adequate monitoring of the core is maintained with one channel bypassed in each group. The arrangement allows the bypassing of one IRM in each rod block logic circuit.

These bypasses are affected by positioning switches in the MCR. A light in the MCR indicates the bypassed condition.

An automatic bypass of the SRM detector position rod block is effected as the neutron flux increases beyond a preset low level on the SRM instrumentation. The bypass allows the detectors to be partially or completely withdrawn as a reactor startup is continued.

An automatic bypass of the RBM rod block occurs whenever power level is < 30% core thermal power or whenever a peripheral control rod is selected. Either of these two conditions indicates that violation of the fuel-cladding integrity safety limit is not threatened, and RBM action is not required.

The RWM rod block function, when not in the sequence control mode, is automatically bypassed when reactor power increases above a preselected value in the power range. It may be manually bypassed for maintenance at any time.

7.7.4.3.4 Arrangement of Rod Block Trip Channels

The same grouping of neutron monitoring equipment (IRM, SRM, and RBM) used in the RPS is also used in the rod block circuitry. One-half of the total number of IRMs, SRMs, and RBMs provide inputs to one of the rod block logic circuits, and the remaining half provides inputs to the other logic circuit.

Scram discharge volume high water level signals are provided as inputs into both of the two-rod block logic circuits. Both rod block logic circuits sense when the high water level scram trip for the scram discharge volume is bypassed. The rod withdrawal block from the RWM trip affects both rod block logic circuits. The rod insert block from the RWM function prevents energizing the insert bus for both notch insertion and continuous insertion.

The APRM and RBM rod block settings in the RUN mode are varied as a function of recirculation flow and core thermal power, respectively. The APRM rod block setting in the STARTUP mode is a fixed value. Analyses show that the settings selected are sufficient to avoid both scram and violation of the fuel-cladding integrity safety limit as a result of a single control rod withdrawal error. Mechanical switches in the SRM and IRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted. Additional detail on all the neutron monitoring system trip channels is available in section 7.5, Neutron Monitoring System. The rod block from scram discharge volume high water level utilizes a nonindicating float switch installed on the scram discharge volume. A second float switch provides an MCR annunciation of increasing level.

7.7.4.4 <u>Control Rod Information Displays</u>

The operator has three different displays of control rod position:

- Rod status display.
- Four-rod display.
- Process computer printout.

These displays serve the following purposes:

- Provide the operator with a continuously available, easily understood presentation of each control rod status.
- Provide continuously available, easily discernible warning of an abnormal condition.

- Present numerical rod position for each rod.

- Log all control rod positions on a routine basis.

The rod status display is located on a control board in the MCR. It provides the following continuously available information for each individual rod:

- Rod position, fully inserted (green).

- Rod position, fully withdrawn (red).

- Rod identification (coordinate position of selected rod, white).

- Accumulator trouble (amber).

- Rod scram (blue).

- Rod drift (red).

Operator display assemblies include the LPRM values for each detector array surrounding the rod selected.

Between the LPRM indicators are four rod position modules. These four modules display rod position in two digits and rod selected status (white light, off or on) for the four rods located within the LPRM detector arrays being displayed. The rod position digital range is from 00 to 48, with 00 representing fully in position and 48, fully out. Each even increment; e.g., 00-02, equals 6 physical in. of rod movement. The four-rod display allows the operator to easily focus his attention on the core volume of concern during rod movements.

Control rod position information is obtained from reed switches in the CRD that open or close during rod movement. Reed switches are provided at each 3-in. increment of piston travel. Since a notch is 6 in., indication is available for each half-notch of rod travel. The reed switches located at the half-notch positions for each rod are used to indicate rod drift. Both a rod selected for movement and the rods not selected for movement are monitored for drift. A drifting rod is indicated by an alarm and red light in the MCR. The rod drift condition is also monitored by the process computer.

Reed switches are also provided at locations that are beyond the limits of normal rod movement. If the rod drive piston moves to these overtravel positions, an alarm is sounded in the control room. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact, because with the coupling in its normal condition, the drive cannot be physically withdrawn to the overtravel position. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position and observing that no overtravel alarm occurs.

The process computer receives position indication from each rod and prints out all rod positions in a prearranged sequence. The operator may order a computer printout any time it is desired. The printout depicts the rod positions in an array corresponding to the other displays and actual core location. The printout is always in the same order; if there is an incorrect input, the printout signifies it by printing either a blank or 99.

All displays are essentially independent of one another. Signals for the rod status display are hard wired from the rod position information system cabinet buffer outputs, so that a signal failure of other parts of the rod position information system cabinet will not affect this display. Likewise, the computer could conceivably fail, and the rod status and rod position displays will continue to function normally.

The following MCR lights or alarms are provided to inform the operator of the conditions of the CRD hydraulic system and the control circuitry (drawing nos. H-19918 and H-19919):

- Stabilizing valve selector switch position.
- Insert bus energized.
- Withdraw bus energized.
- Settle bus energized.
- Withdrawal not permissive.
- Notch override.
- Pressure control valve position.
- Flow control valve position.
- Drive water pump low-suction pressure.
- Drive water filter high differential pressure.
- Charging water (to accumulator) low pressure.
- CRD temperature.
- Scram discharge volume not drained.
- Scram valve pilot air header low pressure.

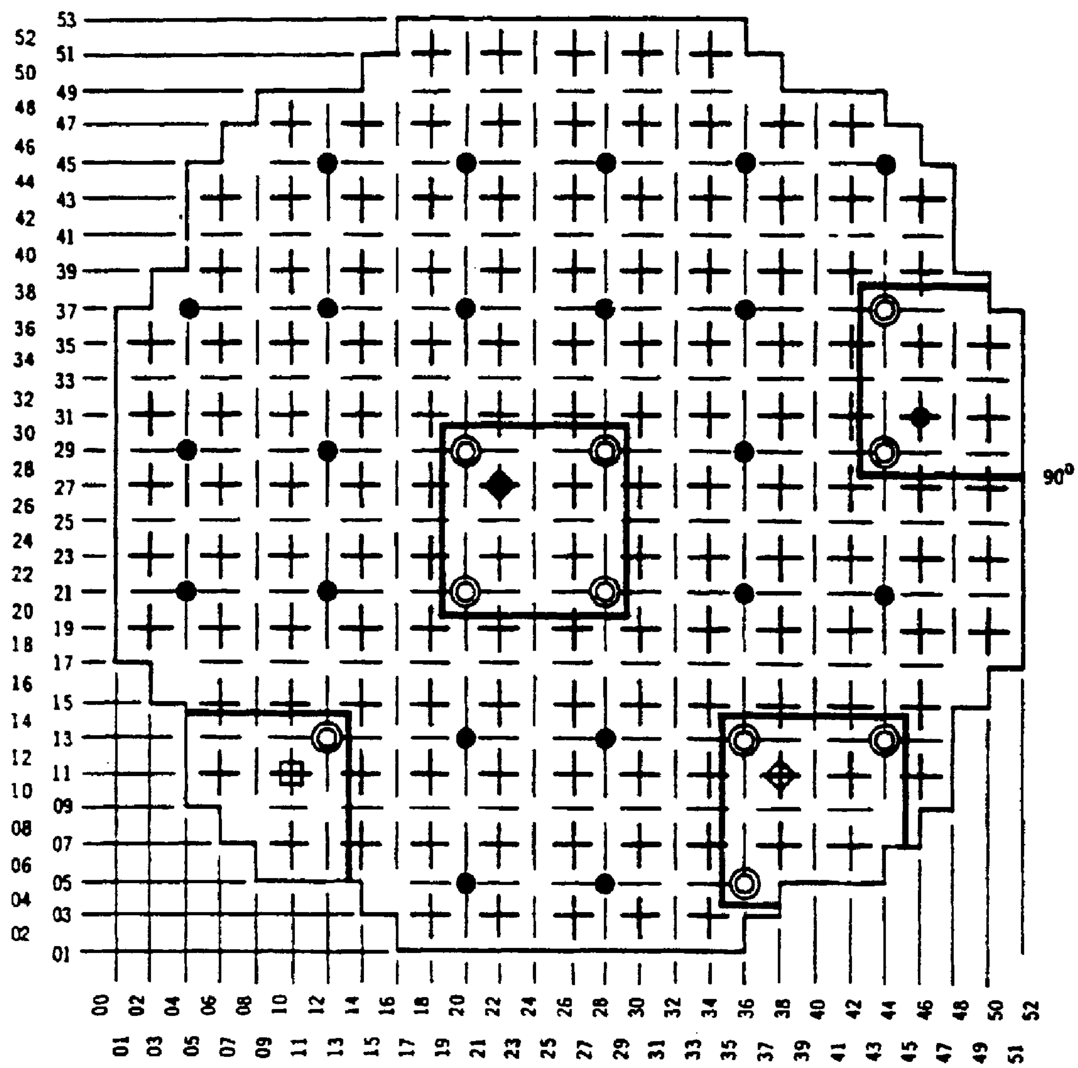
7.7.5 SAFETY EVALUATION

The circuitry described for the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The circuitry is discussed in section 8.2, "Reactor Protection System." Because each control rod is controlled as an individual unit, a failure that results in energizing any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunction of any one control rod. No single failure in the RMCS can result in the prevention of a reactor scram. Repair adjustment or maintenance of RMCS components does not affect the scram circuitry.

7.7.6 INSPECTION AND TESTING

The RMCS can be routinely checked for proper operation by manipulating control rods using the various methods of control. Detailed testing and calibration can be performed by using standard tests and calibration procedures for the various components of the RMCS.

CORE TOP VIEW
0°



LPRM INPUT UPON ROD SELECTION

TYPICAL ROD YIELDING FOUR STRING INPUT

TYPICAL ROD YIELDING THREE STRING INPUT

TYPICAL ROD YIELDING TWO STRING INPUT

TYPICAL ROD YIELDING ONE STRING INPUT

THE LPRMs AND RODS WITHIN THE HEAVILY MARKED LINES AROUND THE SELECTED ROD ARE THOSE PRESENTED ON THE FOUR-ROD DISPLAY.

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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

INPUT SIGNALS TO FOUR-ROD DISPLAY

FIGURE 7.7-1

7.8 REACTOR VESSEL INSTRUMENTATION

7.8.1 POWER GENERATION OBJECTIVE

The power generation objective of the reactor vessel instrumentation is to monitor and transmit reactor vessel parameter information such that the convenient, efficient, and economical operation of the plant is facilitated.

7.8.2 POWER GENERATION DESIGN BASIS

Reactor vessel instrumentation is designed to monitor and transmit sufficient reactor vessel parameter information to the operator such that he is continually able to operate the plant conveniently, efficiently, and economically.

7.8.3 SAFETY OBJECTIVE

The safety design objective of the reactor pressure vessel (RPV) instrumentation is to monitor the key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible in order to avoid:

- Nuclear system stress in excess of that allowed by applicable industry codes.

- The existence of any operating conditions not considered in the safety analysis (HNP-2-FSAR chapter 15).

7.8.4 SAFETY DESIGN BASES

Reactor vessel instrumentation is designed to:

- Provide the operator with sufficient indication of reactor core flowrate during planned operations to maintain proper operating conditions.

- Provide the operator with sufficient indication of RPV water level during planned operations to determine that the core is adequately covered by the coolant inventory.

- Provide the operator with sufficient indication of reactor vessel pressure during planned operations to maintain proper operating conditions.

- Provide the operator with sufficient indication of nuclear system leakage during planned operations to avoid nuclear system stress in excess of that allowed by applicable industry codes.

7.8.5 DESCRIPTION

Drawing nos. H-16062, H-16063, and H-16145 show the numbers, location, and arrangements of the sensors, switches, transmitters/trip units, and sensing equipment used to monitor reactor vessel conditions. Because the reactor vessel sensors used for safety systems, engineered safeguards, and certain control systems have been described and evaluated in other portions of chapter 7, only those sensors that are not required for those systems are described in this section.

7.8.5.1 Reactor Vessel Temperature

Reactor pressure vessel temperature is determined on the basis of reactor coolant temperature. Temperatures which are needed for operation and for compliance with Technical Specifications operating limits are obtained from one of several sources depending upon the operating condition. During normal operation, reactor pressure and/or the inlet temperature of the coolant in the recirculation loops may be used to determine the vessel temperature. Below the operating span of the resistance temperature detectors in the recirculation loop, the vessel pressure is used for determining the temperature. Below 212°F, the vessel coolant temperature is indicative of RPV temperature as shown by the reactor water cleanup inlet temperature indicator. The most convenient source from which to obtain the data discussed above is the process computer system. (Refer to subsection 7.6.8 of the HNP-2 FSAR, Process Computer System, for information on accessing data relative to RPV temperature.) During normal operation, vessel thermal transients are limited by operational constraints on parameters other than temperature. (See section 7.2, Reactor Protection System.)

Reactor vessel thermocouples are provided as a means of observing vessel metal surface temperature behavior in response to vessel coolant temperature changes during startup and power operation testing. Indications based upon the thermocouples are not used for controlling the rate of heating or cooling or limiting the vessel thermal stresses. Selected temperatures are recorded on recorders. Thermocouple and temperature recorder specifications are listed in table 7.8-1.

7.8.5.2 Reactor Vessel Water Level

The RPV water level indication is detected by comparing the pressure exerted by the actual height of water inside the vessel to the pressure exerted by a constant reference column of water outside of the vessel. Lines, which are connected to widely separated nozzles in the reactor vessel, lead from the vessel to locations outside the primary containment where they terminate at instrument racks in the reactor building. Level-measuring instruments are attached to the appropriate sensor lines so the proper differential pressure is applied to the level instruments. A condensing chamber is installed in each of the lines used to provide a reference column of water for level measurements. Two of the reference columns are level measurements. Two of the reference columns are fitted with a temperature compensating column and an auxiliary head chamber to improve the accuracy of level measurement. The reactor vessel instrumentation used for safety systems is described and evaluated in section 7.2. Each of the instrument lines is fitted with one manual isolation valve and one excess flow check valve, both of which are located directly outside the drywell in the reactor building. The instrument lines slope down a minimum of 1/8 in./ft in the direction of the instruments so no air traps are formed. Instrument tubing installed for the analog transmitter trip system (ATTS) is sloped at 1/4 in./ft, unless otherwise technically specified. Pressure and differential pressure-measuring instruments use the same instrument lines, as indicated on drawing no. H-16063.

There are numerous indications of RPV water level in the reactor building. Level-measuring instruments B21-N024A,B; N025A,B; N031A; N036; and N042A indicate locally, as shown on drawing no. H-16063. Some of the instruments derive their level measurements from the instrument lines in which the temperature compensating columns are installed. Thus, temperature compensated, as well as uncompensated, level indications are available in the reactor building.

Eleven separate RPV water level indications are continuously displayed on various boards in the main control room (MCR).

A. MCR level indicators B21-R604A, B and recorders R623A, B have inputs from lines using the temperature compensated reference columns of water. Recorders B21-R623A, B monitor wide-range RPV water level (-150/0/+60-in. water).

B. Level indicators C32-R606A, B, and C provide RPV water level indication for the feedwater control system.

C. Recorders B21-R623A, B display core shroud water level measurement used for containment spray lockout and read full scale during jet pump operation. The Technical Specifications requirement that continuous monitoring of cold shutdown vessel level be displayed is satisfied by recorders B21-R623A, B.

D. Level indicators B21-R605 and C32-R655 use a separate reference column of water located so water level indication is possible all the way to the top of the vessel.

Level recorder C32-R608 receives level signals from level transmitters in the feedwater control system, provides a continuous record of RPV water level in the normal operation range, and provides high- and low-level alarms. Table 7.8-1 lists the specifications for level instruments not previously described with other systems.

A review of RPV water level instrumentation resulted in identification of a potential inaccuracy that would occur under the unusual condition of very high drywell temperature characterized by accident conditions. The effect of this inaccuracy is acceptable from a safety standpoint, but it could result in a reduction in redundancy of the initiating signals of the emergency core cooling system (ECCS) and lead to some misinterpretation of actual RPV water level by the operator.

The -150/0/+60-in. range liquid level instruments have reference columns in the drywell which are heated. Large changes in drywell temperature can result in changes in the temperature of this heated reference column and result in differences between measured and actual RPV water level.

The heated reference leg instrument senses the collapsed liquid level above the elevation of the lower tap inside the reactor vessel by measuring the pressure differential (DP) between the reference leg column and the variable leg column. When the vessel level is low, the variable leg level is low, and the measured DP is large. When the vessel level is high, the variable leg level is high, and the measured DP is small. The DP cell is typically calibrated to give the correct indicated RPV water level when the reactor pressure and temperature are at their normal operating values (~ 1000 psig and 546°F) and when the drywell is at its normal operating temperature.

Large increases in drywell temperature, such as those that could occur during a pipe rupture in the drywell, would cause the reference leg of these instruments to heat up. As the reference leg water temperature increases, the reference leg water density decreases causing the sensed DP to decrease even if the variable leg level and temperature were to remain unchanged. This decreasing DP would register as an increasing vessel level on the DP cell indicator and the remote indicator.

The magnitude of the level indication change depends upon the temperature transient in the drywell, the thermal response time constant of the heated reference leg, and the length of the reference leg water column. If it is conservatively assumed that the drywell is maintained at the maximum temperature, which would result from a small steam line break, that the reference leg has reached its equilibrium temperature, and that the variable leg level is low, the indicated reactor vessel water level can be higher than the true level by 12.7% of the reference leg's total length (scale length + 6-in. top suppression + 6-in. bottom suppression). Actual level indication changes due to increasing drywell temperature can be expected to be smaller than calculated and will occur rather slowly since the thermal time constant of the reference leg is calculated to be 20 to 30 min.

Given the conservative assumptions described above, true RPV water level could fall to below the lower level tap elevation with the instrument still indicating a water level of up to 28 in. (depending on the instrument scale length) above the lower tap elevation. Once true level falls below the lower tap, the instrument will not sense further level decrease. The RPV water level 1 trip point is set high enough above the lower tap to ensure that level trips will occur at the prescribed setpoint. However, the operator could believe the water level is stable at some level when in fact the true level could be lower.

With the exception of the reactor core isolation cooling (RCIC) system and the automatic depressurization system (ADS), all ECCSs start as a result of an RPV water level 1 or 2 or a high drywell pressure signal. The RCIC system starts as a result of RPV water level 2 only, and the ADS initiates on RPV water levels 1 and 3 and high drywell pressure. Since all loss-of-coolant accidents (LOCAs) inside the containment will result in high drywell pressure before RPV water level 1 or 2 is reached, high-pressure coolant injection (HPCI), low-pressure core spray (CS), and low-pressure cooling injection (LPCI) all start during a LOCA regardless of temperature effects on level instrumentation.

The impact of high drywell temperature on the level instrument initiating RCIC and ADS for the three general categories of steam line breaks, assuming HPCI failure, is discussed below. (Steam line breaks lead to larger inaccuracies than water line breaks and were, therefore, selected for detailed study).

A. Breaks > 0.5 ft^2

Because the reactor vessel depressurization rate is sufficiently fast, the ECCS will start on high drywell pressure and vessel level will increase before the ADS level trip is received; therefore, the ADS trip is not required to function.

B. Breaks < 0.1 ft^2

The RCIC system starts and maintains vessel level before the ADS level setpoint is reached; therefore, the ADS trip is neither expected nor required to function.

C. Breaks > 0.1 ft^2 but < 0.5 ft^2

The RCIC system starts and the combination of RCIC and the break depressurizes the vessel sufficiently fast to cause initiation of low-pressure ECCS before fuel-cladding temperature limits are exceeded. Thus, the ADS trip is not required to function.

Drawing no. H-16145, contains a chart showing the relative indicated water levels at which various automatic alarms and safety actions are initiated. Each of the actions listed is described and evaluated in the section where the system involved is described. The following list tells where various level-measuring components and their setpoints are discussed:

Level Instrumentation	Section
Level transmitters/trip units for initiating scram	7.2
Level transmitters/trip units for initiating primary containment or reactor vessel isolation	7.3
Level transmitters/trip units used for HPCI, LPCI, CS, and ADS	7.4
Level transmitters and recorders used for feedwater control	7.10
Level transmitters/trip units used to initiate RCIC and trip RCIC	4.7

The large number of RPV water level indications is sufficient in providing the operator with information with which the adequacy of the coolant inventory to cool the fuel can be determined. In addition, by verifying that RPV water level is not rising to an abnormally high level, the operator is assured that turbines are not endangered by the possibility of water carried into the steam lines. The approach of abnormal conditions is brought to the operator's attention by audible and visual alarms (drawing nos. H-16063 and H-16145). It should be noted that in no case requiring safety system response is operator action required within 10 min after a transient or accident is initiated. All essential protection system responses are completely automatic.

7.8.5.3 Reactor Vessel Coolant Flowrates and Differential Pressures

Drawing nos. H-16062, H-16063, and H-16145 show the flow instruments, differential pressure instruments, and recorders provided so that the core coolant flowrates and the hydraulic performance of reactor vessel internals can be determined.

The differential pressure between the throat of each of the jet pumps and the core inlet plenum is measured and indicated in the MCR. Four jet pumps, two associated with each recirculation loop, are specially calibrated. They are provided with special pressure taps in the diffuser sections. The differential pressure measured between the special taps and the throat allows precise flow calibration using jet pump prototype test performance data. The flowrates through the remaining jet pumps are calculated from the flows shown by the calibrated jet pumps. The flowrates through the jet pumps associated with each recirculation loop are summed to provide control room indication of the core flowrate associated with each recirculation loop. The total flows for both recirculation loops are again summed to provide a recorded control room indication of the total flow through the core.

Total core flow indication derived from the measured flow in the jet pumps is provided during the operation of a single recirculation loop by subtracting the reverse flow signal from the forward flow signal of the active jet pumps. This function is provided automatically anytime a single recirculation pump is in operation (drawing no. H-19907).

A differential pressure transmitter and indicator are provided to measure the pressure difference between the reactor vessel above the core assembly and the core inlet plenum. This indication can be used to determine the overall hydraulic performance of the jet pump group and to check the total core flowrate. These indications are available in the MCR.

A differential pressure transmitter is provided to indicate core pressure drop by measuring the pressure difference between the core inlet plenum and the space just above the core support assembly. The line used to determine the pressure in the core inlet plenum is the same line provided for the standby liquid control system. A separate line is provided for the pressure measurement above the core support assembly. The differential pressure is both indicated and recorded in the MCR.

Instrument lines leading from the reactor vessel to locations outside the drywell are provided with one manual isolation valve and one excess flow check valve. All of the flow and differential pressure instruments are located outside the primary containment.

This instrumentation permits the determination of total core flow in two ways. The first method is the readout of the summed flow measurements from all the jet pumps. The second method includes the use of jet pump prototype performance data, the jet pump differential pressures, and the differential pressure between the reactor vessel annulus and the core inlet plenum. A temporary correlation can also be made to define core flow as a function of reactor operating power level and the readout of the pressure difference between the reactor vessel annulus and the core inlet plenum. This correlation is of a temporary nature because it will change with a fixed-core arrangement over a period of time as a result of crud buildup on the fuel. The control room flowrate readouts of the specially calibrated jet pumps can be used to cross-check the flowrate readouts of all the other jet pumps. A discrepancy in the cross-checks is reason enough to check local flow indications.

7.8.5.4 Reactor Vessel Internal Pressure

Reactor vessel internal pressure is detected by pressure sensors, indicators, and transmitters/trip units from the same instrument lines used for RPV water level measurements. Two pressure indicators (B21-R004A,B) that sense pressure from different, separated instrument lines provide pressure indications in the reactor building. Five reactor vessel pressure indicators (B21-R623A,B and C32-R605A,B,C) are provided in the MCR. These come from the three pressure transmitters used in the feedwater control system and from two transmitters/trip units from the analog transmitter trip system (ATTS). Reactor vessel pressure is continuously recorded in the MCR on recorders (C32-R608, C32-R609). The recorders receive a pressure signal from one of the feedwater control system pressure transmitters.

The following list shows where reactor vessel pressure measuring instruments used for the automatic control of equipment or systems are discussed:

Pressure Instrumentation	Section
Pressure transmitters/trip units used to initiate a scram.	7.2
Pressure switch to activate safety relief valves.	4.4
Pressure transmitters/trip units used for HPCI, CS, and LPCI.	7.4
Pressure transmitters and recorders used for feedwater control.	7.10
Differential pressure switches Measuring differential pressure between inside of CS sparger pipes and core inlet above the core support assembly.	7.4

7.8.5.5 Reactor Vessel Top Head Flange Leak Detection

A connection is provided on the reactor vessel flange into the annulus between the two metallic seal rings used to seal the reactor vessel and top head flanges. This connection permits detection of leakage from the inside of the reactor vessel past the inner seal ring. The connection is piped to a pressure switch having an associated alarm in the MCR. A drain line is provided from the connection to the drywell equipment sump in order to allow resetting of the pressure switch and to facilitate maintenance. This drain line is controlled by two manually operated, normally closed gate valves. The arrangement is shown on drawing no. H-16062. The specification for the pressure switch is given in table 7.8-1.

7.8.6 SAFETY EVALUATION

The reactor vessel instrumentation is designed to provide sufficient continuous indication of key reactor vessel operating parameters during planned operations such that the operator can efficiently monitor these parameters. The redundancy of all indicators provided assures that the possibility that all instrumentation could be lost simultaneously is so remote as to be negligible. In addition, sensors providing safety signals to the reactor protection system and engineered safeguards systems for scram and isolation functions are separate from these indicator sensors such that loss of indication does not directly obviate protection against accidents and transients.

7.8.7 INSPECTION AND TESTING

Pressure, differential pressure, water level, and flow instruments are located in the reactor building and are piped so that calibration and test signals can be applied during reactor operation, if desired.

TABLE 7.8-1 (SHEET 1 OF 2)

REACTOR VESSEL INSTRUMENTATION INSTRUMENT SPECIFICATIONS[(a)]

Measures Variable	Instrument Type	Normal Range	Instrument Loop Accuracy	Trip Setting
RPV surface temperature	Thermocouple	0-600°F	ASA C96.1	-
RPV top head surface temperature	Thermocouple	0-600°F	ASA C96.1	-
RPV top head flange surface temperature	Thermocouple	0-600°F	ASA C96.1	-
RPV surface temperature	Temperature recorder	0-600°F	± 1%	-
RPV water level (temperature compensated) (B21-R604A,B) (B21-R623A,B)	Level indicators Level recorders	-150/0/+60 in.[(b)]	± 41.5 in.[(c)]	
RPV water level (shutdown) (B21-R605)	Level indicator	-17/0/+383 in.[(b)]	± 43.5 in.[(c)]	-
RPV water level (shroud water) (B21-R623A, B)	Recorder	-317/-17 in.	± 11 in.	-
Specially calibrated jet pump flow transmitter	Differential pressure transmitter	0-40 psi	± 1/2%	-
Jet pump flow transmitter	Differential pressure transmitter	0-40 psi	± 1/2%	-
Specially calibrated jet pump flowrate	Flow indicator	0-6x10^6lb/h	± 2%	
Jet pump flowrate	Differential pressure indicator	0-100%	± 2%	-
Specially calibrated jet pump flowrate	Square root extractor	-	± 1/2%	-
Jet pump flowrate	Square root extractor	-	± 1/2	-
Core total flow	Flow summer	-	± 1/2	-

TABLE 7.8-1 (SHEET 2 OF 2)

Measures Variable		Instrument Type	Normal Range	Instrument Loop Accuracy	Trip Setting
Pressure difference across core support assembly		Differential pressure recorder	0-30 psid	± 2	-
Jet pump developed head		Differential pressure transmitter	0-30 psid	± 1	-
Jet pump developed head		Differential pressure indicator	0-30 psid	± 2	-
Differential pressure across core support assembly		Differential pressure transmitter	0-30 psid	± 1	-
RPV pressure (B21-R004A,B; B21-R623A,B)		Pressure indicators Pressure recorders	0-1500 psig 0-1500 psig	± 2	-
RPV flange leak detection piping internal pressure		Pressure switch	0-1500 psig	± 2	600 psig
RPV level feedwater	(C32-R606A,B)	Level indicators	0-60 in.	± 2	-
control system	(C32-R608)	Level recorder	0-60 in.	± 1/2	-
Reactor pressure	(C32-R605A,B,C)	Pressure indicators	0-1200 psig	± 2	-
(feedwater	(C32-R608)	Pressure recorder	0-1200 psig	± 1/2	-
control system)	(C32-R609)	Pressure recorder	700-1300 psig	± 1/2	-

a. Other instruments measuring reactor vessel variables are discussed in FSAR sections where the systems using the instruments are described.
b. Zero scale is instrument zero.
c. Includes 28.5 in. required to be assumed by SIL 299.

7.9 RECIRCULATION FLOW CONTROL SYSTEM

7.9.1 POWER GENERATION OBJECTIVE

The objective of the recirculation flow control system (RFCS) is to control reactor power level over a limited range by controlling the flowrate of the reactor recirculating water.

7.9.2 POWER GENERATION DESIGN BASES

A. The RFCS is designed to allow variation of the recirculation flowrate.

B. The RFCS is designed to allow manual recirculation flow adjustment so manual control of reactor power level is possible.

7.9.3 SAFETY DESIGN BASIS

The RFCS is designed so no abnormal anticipated operational occurrence resulting from a malfunction in the RFCS can result in damaging the fuel or exceeding the nuclear system pressure limits.

7.9.4 DESCRIPTION

7.9.4.1 General

Depending on whether the unit is operating in one recirculation loop operation or two recirculation loop operation, reactor recirculation flow is changed by adjusting the speed of one or both of the two reactor recirculation pumps. The RFCS controls the power supplied to the recirculation pump motors by adjusting the frequency of the electrical power supplied to the recirculation pump motors. Thus, RFCS can effect changes in reactor power level.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. The additional neutron moderation increases the reactivity of the core which causes the reactor power level to increase. The increased steam generation rate increases the steam volume in the core with a consequent negative reactivity effect, and a new steady-state power level is established. When recirculation flow is reduced, the power level is reduced in the reverse manner.

Figure 7.9-1 illustrates how the RFCS operates in conjunction with the turbine controls.

Each recirculation pump motor has its own adjustable speed drive (ASD) for a power supply. To change the speed of the reactor recirculation pump, the ASD varies the frequency and magnitude of the voltage supplied to the pump motor to give the desired pump speed. A manually set signal from the master controller (manual speed control pushbutton switches in the main control room (MCR)) adjusts the speed setting of the speed control system for each ASD.

The reactor power change resulting from the change in recirculation flow causes the initial pressure regulator to reposition the turbine control valves (TCVs).

7.9.4.2 Adjustable Speed Drive

Each ASD supplies power to its associated recirculation pump motor. Each of the two ASDs and its controls are identical; therefore, only one description of the ASDs is given. The ASD can continuously supply power to the pump motor at any speed between 345 rpm and 1830 rpm; however, the ASD controls limit the minimum pump speed to ~366 rpm (includes pump slippage). The maximum pump speed is limited so as not to exceed the maximum allowable core flow. Overfrequency relays that monitor ASD output frequency will trip the ASD as a backup to the ASD controller maximum speed limiter. The ASD is capable of starting the pump and accelerating it from standstill to the desired operating speed when the pump motor thrust bearing is fully loaded by reactor pressure acting on the pump shaft.

The main components of the ASD set are described below:

A. Input Power Cabinet

   The input power cabinet contains terminals for incoming power cables, potential and current transformers, and instrumentation for input voltage signal conditioning for internal controls. The stainless steel ground pads are welded to the cabinet.

B. Transformer Cabinet

   The transformer cabinet consists of a power transformer which acts as an isolation transformer with four secondaries per phase. The phase angle of the four secondaries differs in phase angle by 15 degrees. The transformer primary and secondary windings are built using copper tubing with drive coolant flowing through the tubing.

C. Fuse/Precharge/Control (FPC) Cabinet

   The control interface for the ASD is comprised of hardwired analog and digital inputs and outputs signals and serial interface for plant safety parameter display system (SPDS) and the ASD PLC system. The serial interface will utilize industry standard control interface data highway protocol. The serial interface will allow transfer of data such as for status, monitoring, alarm, historic, and diagnostic information. Critical signals required for the control of the ASD will be hard wired. Additionally, the ASD will provide a local emergency stop button, a local remote selector switch, a local display of key operating parameters, and alarms.

D.. Cell Cabinet

The cell cabinet contains 12 power cells, 4 per phase, which are a static pulse width modulated (PWM) power converter. Each power cell consists of a three-phase diode rectifier fed by one of the secondaries and capacitors. The rectifier charges the capacitor bank that feeds a single-phase bridge of four insulated gate bipolar transistors (IGBT), which generate the PWM output of the power cells. The phase shifted secondaries cause harmonic cancellation between the reflected secondary currents.

E. Output Power Cabinet

The output power cabinet houses the output medium voltage line terminals and stainless steel ground pads. The output line current and voltage transformers are also included in the output power cabinet.

F. Relay Cabinet

The ASD system will include various protection features for the internal components and protection for the motor connected to its power output. The motor protection provided in the ASD will include protection against overvoltage, overspeed, motor ground fault, motor thermal overload, instantaneous overcurrent, open output phase, and torque limit. The protective relays are configured in two-out-of-three trip logic to preclude single-point failure.

G. Coolant Cabinet

The ASD transformer and power cells require supplemental cooling. An external liquid-to-liquid heat exchanger provides the required cooling. This arrangement requires providing 600-V power sources to two cooling pumps mounted in the cooling cabinet. The cabinet houses a PLC-based control system with a human machine interface (HMI), a coolant pump control mode selector switch, and a coolant pump hand mode selector switch. The PLC control system for the cooling system is connected via a redundant network to the ASD PLC control system.

7.9.4.3 Speed Control Components

The speed control system controls output frequency and voltage of each ASD. The ASD can be manually controlled individually or jointly. The signals from the master controller are fed to two separate sets of control system components, one for each ASD. The control system components for each ASD described below are a master controller and ASD controller:

A. Master Controller (common to both ASDs)

The master controller provides signals to each ASD controller to increase/decrease speed incrementally via manual pushbutton switches located in the MCR to manually control both recirculation pumps.

During system operation, the master controller sends a signal output to the ASD controller to limit ASD output frequency if either the recirculation pump discharge valve is not fully open or total feedwater flow is < 20% of rated flow. This limiting action prevents pump overheating should the discharge valve be closed and protects the recirculation pump against possible cavitation due to low feedwater flow.

The master controller will also send an output signal to the ASD controller to limit ASD output frequency on any of the following conditions:

- If any one feedwater pump trips, and either a low-level alarm is initiated or total steam flow is greater than the capacity of a single reactor feed pump, recirculation speed is reduced to allow the resultant reactor power to remain within the capabilities of the feedwater system.

- Low vessel level results in a recirculation speed reduction to avoid a reactor scram from other feedwater transients.

- Inadequate net positive suction head at a condensate booster pump results in a recirculation flow runback, reducing core flow to prevent tripping of a condensate booster pump or reactor feed pump.

- Upon indication of a scram, as determined by changes in the vessel level and steam flow signals, recirculation flow is run back to limit water level shrink following the scram.

B. ASD Controller (one for each ASD)

The ASD controller initiates all ASD output frequency changes and controls all speed change ramp rates. Initial ASD start to minimum pump speed and ASD shutdown are also controlled by the ASD controller. Abnormal conditions affecting the ASD are alarmed in the MCR.

C. Speed Indicator (one for each ASD)

Each ASD controller provides a signal to the master controller representing drive output frequency. The master controller converts this signal and supplies a signal representing sync speed to the speed indicator.

D. Speed and Speed Demand Indicator (one for each ASD)

Two indicators (speed and speed demand) are provided to assist the operator. The speed indicator shows the actual percent sync speed, and the speed demand indicator shows the output demand from the ASD controller

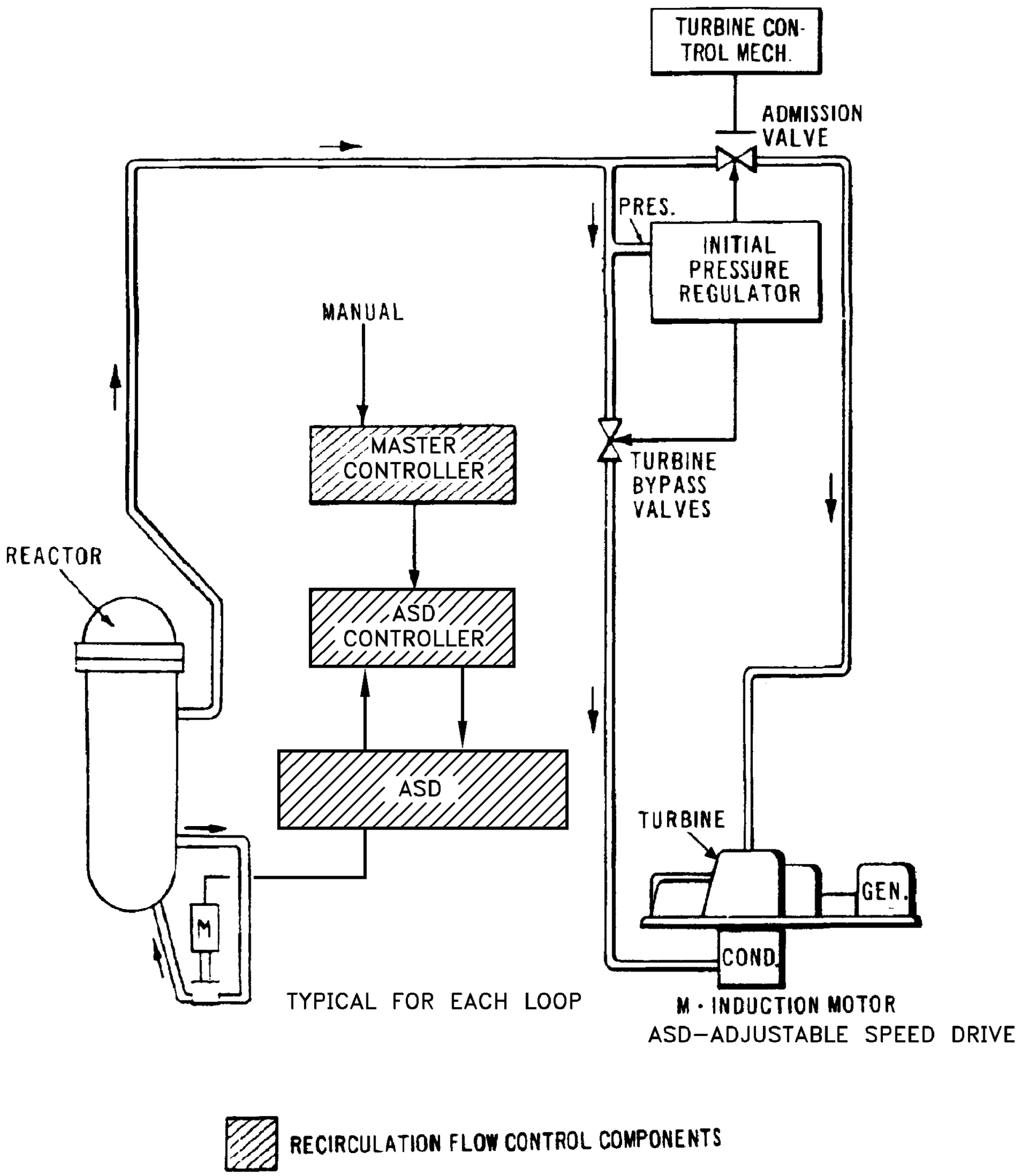
7.9.5 SAFETY EVALUATION

The RFCS is not required for the safe shutdown of the plant and is not required during or after accident conditions.

Anticipated operational occurrence (AOO) analyses described in HNP-2-FSAR chapter 15, Safety Analysis, show that no malfunction in the RFCS can cause an AOO sufficient to damage the fuel barrier or exceed the nuclear system pressure limits, as required by the safety design basis.

7.9.6 INSPECTION AND TESTING

Each ASD control system and the master controller are functioning during normal power operation. Any abnormal operation of these components can be detected during operation. The components which do not continually function during normal operation can be tested and inspected for calibration and operability during scheduled plant shutdowns. All the RFCS components are tested and inspected according to the component manufacturers' recommendations.



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RECIRCULATION FLOW CONTROL ILLUSTRATION

FIGURE 7.9-1

7.10 FEEDWATER CONTROL SYSTEM

7.10.1 POWER GENERATION OBJECTIVE

The objective of the feedwater control system is to maintain a preestablished water level in the reactor vessel during normal plant operation.

7.10.2 POWER GENERATION DESIGN BASES

The feedwater control system regulates the feedwater flow so that the proper water level in the reactor vessel is maintained according to the requirements of the steam separators and to prevent uncovering of the reactor core over the entire power range of the reactor.

7.10.3 DESCRIPTION

The feedwater control system, during normal plant operation, automatically regulates feedwater flow into the reactor vessel. The system is capable of being manually operated. An instrumentation and electrical diagram (IED) for the feedwater control system is provided on drawing no. H-16567.

The feedwater flow control instrumentation measures the water level in the reactor vessel, the feedwater flowrate into the reactor vessel, and the steam flowrate from the reactor vessel. During normal operation, these three measurements are used for controlling feedwater flow.

The optimum reactor vessel water level is determined by the requirements of the steam separators which limit the water carryover with the steam going to the turbines and the steam carryunder with the water returning to the core. For optimum limitation of carryover and carryunder, the steam separators require a decrease in reactor vessel water level as a function of an increase in reactor power level. The water level in the reactor vessel is maintained within ± 2 in. of the optimum level during steady-state operation. This control capability is achieved during plant load changes by balancing the mass flowrate of feedwater to the reactor vessel with the steam flow from the reactor vessel. The feedwater flow regulation is achieved by adjusting the speed of the turbine-driven feedwater pumps.

7.10.3.1 Reactor Vessel Water Level Measurement

Reactor vessel water level is measured by three identical, independent sensing systems (drawing no. H-16567). A differential pressure transmitter senses the difference between the pressure due to a constant reference column of water and the pressure due to the variable height of water in the reactor vessel. A differential pressure transmitter is installed on lines that serve other systems (section 7.8, Reactor Vessel Instrumentation). A pressure transmitter supplies a reactor vessel pressure signal. Each transmitter is powered by an independent power source. A programmable computing station selects the median signal from the level measurements. The master level controller uses the median level signal as its primary input.

One of the three level signals is also sent to the master level controller without passing through the median selector. This signal is used for control if the median signal is not available due to a module failure or a loss of power to the median selector. The operator is able to manually bypass the median level and use the selected level signal as the control input. Each individual level measurement is compared to the median signal, and a deviation alarm is generated if a wide deviation (more than 5 in.) is sensed. The reactor vessel water level and pressure from each sensing system are indicated in the main control room (MCR). The median water level and the selected reactor vessel pressure signals are continually recorded in the MCR. The MCR recorder also calculates the median water level from the same three level signals and compares the results to the median selector output, generating an alarm if there is a wide deviation indicative of a failing module. The MCR recorder also calculates the median water level from the same three level signals and compares the results to the median selector output, generating an alarm if there is a wide deviation indicative of a failing module. A separate level-sensing loop provides a signal in the MCR to indicate reactor water level in the overfill range.

7.10.3.2 Steam Flow Measurement

A differential pressure transmitter senses the steam flow at each main steam line flow restrictor. A programmable computing module performs the square root function and multiplication by the flow constant, and sums the flow signals. The total steam flow signal is sent to the process computer, the control panel recorder, and the master level controller. The individual flow signals are sent to the emergency response facility and the control panel indicators. The individual steam flows are compared to the average and a deviation (greater than a preset value) will generate an alarm condition. Digital outputs indicating a steam deviation are processed with the feedwater flow deviation alarm to provide a digital input to the master level controller denoting a bad quality input. The bad quality input will trigger the master level controller to switch to single-element control.

7.10.3.3 Feedwater Flow Measurement

Differential pressure transmitters sense feedwater flow at flow elements in each feedwater line. A programmable computing module performs the square root function and multiplication by the flow constant, and sums the two flow signals. The individual flow signals are sent to the emergency response facility, the process computer, and the control panel indicators. Total feedwater flow is also recorded in the MCR. Total feedwater flow is monitored to provide low feedwater flow digital outputs to the reactor recirculation pumps.

The two feedwater flow signals are compared to each other and any deviation (greater than a preset value) or an individual bad quality signal will generate an alarm condition.

Digital inputs and failure indications from the steam flow signal processors along with the feedwater flow deviation alarm are used to produce a digital output indicating a bad quality flow input or processor failure which is sent to the master level controller. The master level controller will switch to single-element control upon the receipt of a digital signal representing either bad feedwater flow or steam flow signal. An indicating light indicates when the controller is in three-element mode.

7.10.3.4 Feedwater Control Signal

The following components are operated either manually or automatically to produce the feedwater control signal:

A. Master Level Controller

The master level controller performs either single-element or three-element control based upon which control the operator selects and the status of the digital input from the feedwater flow signal processor. The master level control will only switch to three-element when the operator selects three-element control and the status of the three-element enable signal from the feedwater flow signal processor is positive (close contact). If the three-element enable signal goes negative when the master level controller is in three-element control, the master level controller will switch to single-element control. After restoration of the failed signal, the operator must reset the condition by first positioning the mode selector switch to single-element and then changing to three-element control.

The master level controller uses the median level signal as its primary input if the operator has selected this mode. However, if the median selector module fails, the master level controller will switch to the backup level signal. The operator selects this signal (from transmitter A or B or C) using the control panel switch.

B. Manual/Automatic Transfer Station (one for each reactor feed pump)

The manual/automatic transfer station is a manual controller with a transfer switch and an output indicator. While each pump is being controlled by the master level controller, the transfer switch is positioned so that the manual controller is bypassed and the level controller signal goes through to control the feedwater pump turbines. During startup or when manual control is desirable, the transfer switch blocks the master level controller signal, and the operator provides the feedwater control signal at the manual/automatic transfer station.

Manual/automatic transfer stations assume control of reactor water level in single element control using the backup level signal upon the failure of the master level controller or the loss of signal from the master level controller. If the manual/automatic station enters the backup mode, it will continue in this mode until the manual/automatic station is transferred to manual and back to auto. The other manual/automatic station will switch to manual and hold its output if power is still available. If power to a manual/automatic station is lost, the RFPT speed controller will switch to its manual mode. If this occurs the operator can change the speed of the RFPT using the speed setter switch on the MCR panel.

7.10.3.4.1 Normal Automatic Operation

The ability of the feedwater control system to maintain reactor vessel water level within ± 5 in. of optimum water level during plant load changes is accomplished by the three-element control signal.

Three-element control is executed as follows: The difference between the total steam flow and the total feedwater flow is added to the reactor level signal. The control algorithm uses this sum as input to provide the final control signal. If steam flow is greater than feedwater flow, the output is increased from its normal value when steam and feedwater flows are equal. The reverse is also true.

7.10.3.4.2 Optional Automatic Operation

The single-element control signal (reactor vessel water level) can be used to replace the three-element control signal. In such case, the operator switches to the reactor water level signal, which controls reactor water level in accordance with the controller setpoint.

7.10.3.4.3 Auxiliary Functions

The three level signals provide a two-out-of-three logic to trip the reactor feedwater pumps on reactor high water level. The level control system also provides interlocks and control functions to equipment external to this system. The reactor recirculation system logic is as follows:

- If any one feedwater pump trips, and either a low-level alarm is initiated or a total steam flow is greater than the capacity of a single reactor feed pump, recirculation speed is reduced to allow the resultant reactor power to remain within the capabilities of the feedwater system.

- Low vessel level results in a recirculation speed reduction to avoid a reactor scram from other feedwater transients.

- Inadequate net positive suction head (NPSH) at a condensate booster pump results in a recirculation flow runback, reducing core flow to prevent tripping of a condensate booster pump or reactor feed pump.

- Upon indication of a scram, as determined by changes in the vessel level and steam flow signals, recirculation flow is run back to limit a water level shrink following the scram.

- Upon sustained low feedwater flow, reactor recirculation flow is reduced to ensure adequate NPSH for the recirculation system.

7.10.3.5 Turbine-Driven Feedwater Pump Controls

Feedwater is delivered to the reactor vessel by two turbine-driven feedwater pumps. The feedwater pumps operate in parallel. The turbines are normally driven by low-pressure steam supplied from the main turbine crossaround steam line.

The turbine speed is controlled by an electrohydraulic control system. During normal operation, the three-element control signal is fed to the control mechanism of each operating turbine. The turbine control mechanisms adjust the speed of the associated turbines so that feedwater flow is proportional to the feedwater control signal.

7.10.4 INSPECTION AND TESTING

All feedwater control system components can be tested and inspected according to manufacturers' recommendations. This can be done prior to plant operation and during scheduled shutdowns. Reactor vessel water level indications from the three water level sensing systems can be compared during normal operation to detect instrument malfunctions. Steam mass flowrate and feedwater mass flowrate can be compared during constant load operation to detect inconsistencies in their signals. The level controller can be tested while the feedwater control system is being controlled by the manual/automatic transfer stations.

7.11 PRESSURE REGULATOR AND TURBINE-GENERATOR CONTROL SYSTEM

The pressure regulator and turbine-generator control system was evaluated for changes due to thermal power optimization (2804 MWt) and reactor operating pressure increase to 1060 psia with no significant impact.[1, 2]

7.11.1 POWER GENERATION OBJECTIVE

The power generation objective of the pressure regulator and turbine-generator control system is to maintain constant reactor pressure over the operating load.

7.11.2 POWER GENERATION DESIGN BASES

In conjunction with the reactor recirculation flow control system (RFCS), the pressure regulator and turbine-generator control system maintains constant reactor pressure (constant within the range of the pressure regulator proportional band which is typically a 30-psi drop from 0% to 30% load) during normal operation and operates the steam bypass system up to ~ 21% of full load to maintain constant reactor pressure during plant startup, shutdown, and normal operation.

The pressure regulator and turbine-generator control system accomplishes the following itemized control functions:

- Controls speed and acceleration from 0 to 110% speed with nominal speed reference settings at 0%, 6%, 30%, 85%, 100%, and overspeed.
- Operates the steam bypass system to keep reactor pressure within limits.
- Controls reactor pressure from 150 psig to 1050 psig.
- Matches nuclear steam supply to turbine steam requirements using the following functions:
    - Adjustment of recirculation system flow to satisfy the load requirement as determined by the operator.
    - Adjust the pressure reference of the pressure control unit transiently to improve the load response of the plant.

7.11.3 DESCRIPTION

Reactor pressure regulation and turbine-generator controls and protection are performed by the GE Speedtronic Mark VI electrohydraulic control (EHC) system. The Mark VI is a fully programmable, triple modular redundant (TMR) process control system which couples GE's extensive steam turbine and BWR reactor control application and design experience with modern electronic hardware and software. This allows immediate access to all major control functions, extensive monitoring capabilities, and many built-in features that automatically protect the turbine-generator from a variety of abnormal operating conditions such as turbine overspeed, loss of oil pressure, and LP exhaust hood overheating.

The Mark VI controller performs the following basic turbine control and pressure regulation functions:

- Controlling turbine speed and acceleration through the entire speed range, including overspeed testing and protection.

- Controlling turbine megawatt production using the turbine control valves to regulate the steam flow.

- Maximum combined flow limiting based on total control valve and bypass valve position.

- Detecting and alarming abnormal conditions and events based on the interaction of external sensors and devices and the application code.

- Detecting dangerous/undesirable operating conditions which require tripping of the turbine.

- Self-monitoring of the Mark VI subsystems, including power supplies, redundant control circuits, and sensors.

- Controlling and supervising the operational testing of steam valves and turbine protective devices.

- Warming of the valve chest and high-pressure turbine section by pressurization while on turning gear.

- Regulating main steam (throttle) pressure as required by reactor power level from zero speed to full load. Pressure regulation is transferred to the bypass valves when the turbine/generator is flow or load setpoint limited.

- Automated reactor cooling using the bypass valves.

7.11.3.1 Normal Control Operation

Normal operating control of the pressure regulator and turbine control system is represented by the Mark VI BWR functional diagram (figure 7.11-1). The control system can be divided into subsystems designated as turbine controller and pressure controller.

Following are the major functional components processed in the turbine controller:

- Controlling turbine speed.
- Controlling turbine load.
- Controlling and monitoring the steam flow control valves.
- Controlling turbine pre-warming.
- Preventing an overspeed event.
- Protecting against unsafe operating conditions.

Following are the major functional components processed in the pressure controller:

- Controlling inlet pressure.
- Controlling and monitoring the turbine steam bypass system.
- Protecting against unsafe operating conditions.
- Controlling reactor cooldown.

7.11.3.2 Emergency Control Operations

The purpose of the protection system is to detect undesirable or dangerous operating conditions associated with the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the subsequent action.

Any trip action for the Mark VI control system results in dumping the emergency trip system (ETS) hydraulic fluid pressure, thereby causing rapid closure of all ETS controlled steam admission valves. The ETS pressure is the fundamental permissive for the control system to be reset and allow the turbine steam admission valves to be opened. Provisions are also made to test most of the components in the trip system while the turbine-generator unit is on line.

Other protective functions like power load unbalance and intercept valve tripper act on the fast-acting solenoid valves of the primary steam valves to permanently or momentarily trip the valves closed. These fast-acting solenoid valves cause rapid steam valve closure by depressurizing the ETS header locally at the valve actuator.

Overspeed Protection

The Mark VI's electronic overspeed system is designed to protect the steam turbine against possible damage caused by excessive turbine shaft speed. Under normal operation, the speed/load loop controls the shaft's speed. This overspeed system would be called upon only if that control loop, or a device contained therein, failed.

The overspeed protection system consists of a primary and an emergency overspeed protection system. The primary overspeed system is part of the normal speed control system and uses magnetic pickups to sense turbine speed, speed-detection software, and associated logic circuits.

The emergency or backup overspeed system consists of an independent 2-out-of-3 voting electronic overspeed protection <P> module that has replaced the original mechanical overspeed bolt.

Emergency Trip System

Emergency turbine tripping action protects the turbine-generator against damage from uncontrolled overspeed or other potentially damaging conditions.

The original equipment, front standard mounted, master trip solenoid arrangement was replaced by dual two-out-of-three trip manifold assemblies. In essence, there are two identical hydraulic trip manifolds, each with the capability to completely dump the hydraulic trip header to the hydraulic tank reservoir. The design is based on the two-out-of-three voting logic concept, i.e., for a trip to occur, two of the three controlling solenoids and valves on a single manifold must move to the trip position in order to depressurize the hydraulic trip header and complete the turbine trip process. The trip solenoids are deenergized to trip.

In addition to the above trips, this system trips the unit closing all valves, therefore shutting down the turbine on the following signals:

- Turbine ~ 10% above rated speed; on overspeed.
- Turbine ~ 12% above rated speed while testing the overspeed trip device.
- Vacuum decreases to less than a preselected value; this circuitry meets IEEE 279 to the extent practical considering seismic limitations.
- Excessive thrust-bearing wear.
- Prolonged loss-of-generator stator coolant at loads in excess of a predetermined value.
- External trip signals including remote manual trip.
- Loss-of-hydraulic fluid supply pressure.

- Low lubrication oil pressure.
- Operation of the manual mechanical trip at front standard.
- High level in moisture separators.
- Reactor pressure vessel water level 8.
- Load/flow mismatch.

Analyses have been performed to determine the maximum possible speed attained by the turbine-generator assembly if it is tripped by those events mentioned in the first two listings. The conservative assumptions are made that the unit is carrying full load and that the first line of defense did not operate to keep speed below the emergency trip setting. For these conditions, the primary overspeed protection actuates a full trip at 10% overspeed, and the resulting shaft speed is < 120% of rated speed. If this trip fails, then the backup comes into action at 110.5% of rated speed. For this condition, the shaft speed is slightly higher but still should not exceed 120% of rated speed.

Calculations of a hypothetical runaway condition indicate probable last state wheel failure due to overstress at ~ 175% rated speed, assuming buckets are still intact. If the buckets have failed prior to this speed, then considerable high rotational speeds are possible prior to wheel failure.

7.11.4 POWER GENERATION EVALUATION

The pressure regulator and turbine-generator control system design is such that it provides a stable control response to normal load fluctuations.

The intercept valves operate independently of the control and stop valves to throttle steam and to prevent a turbine overspeed condition following turbine trip; design features to specifically prevent intercept valve closure before stop valve closure are not included although precautions are taken in the design of the circuitry to avoid this occurrence.

However, even if the intercept valves did close before the stop valves, an overpressurization condition would not occur due to four relief valves with setpoint's at ~ 230 psig located between the intercept valves and reheaters. These valves are sized for full reactor flow and discharge into the main condenser. The lifting of these valves results in a loss of condenser vacuum.

The loss of condenser vacuum causes a stop valve closure (as well as main steam isolation valve closure) which prevents further steam flow. Nevertheless, the turbine casing is designed to withstand the conditions resulting from the worst reactor overpressure event discussed in HNP-2-FSAR chapter 15.

The main turbine bypass valves are capable of responding to the maximum closure rate of the turbine control valves such that reactor steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves (~ 21% of full load).

Load rejections in excess of bypass valve capacity and plant auxiliary loads may initiate excessive turbine speed increase, initiating control valve fast closure; this initiates a scram before reactor neutron flux or pressure has reached the trip level. Any condition causing the turbine stop valves to close also directly causes a scram.

Loss of electrical or hydraulic power causes all valves to close. In the event that the control valves are failed fully closed, the reactor scrams.

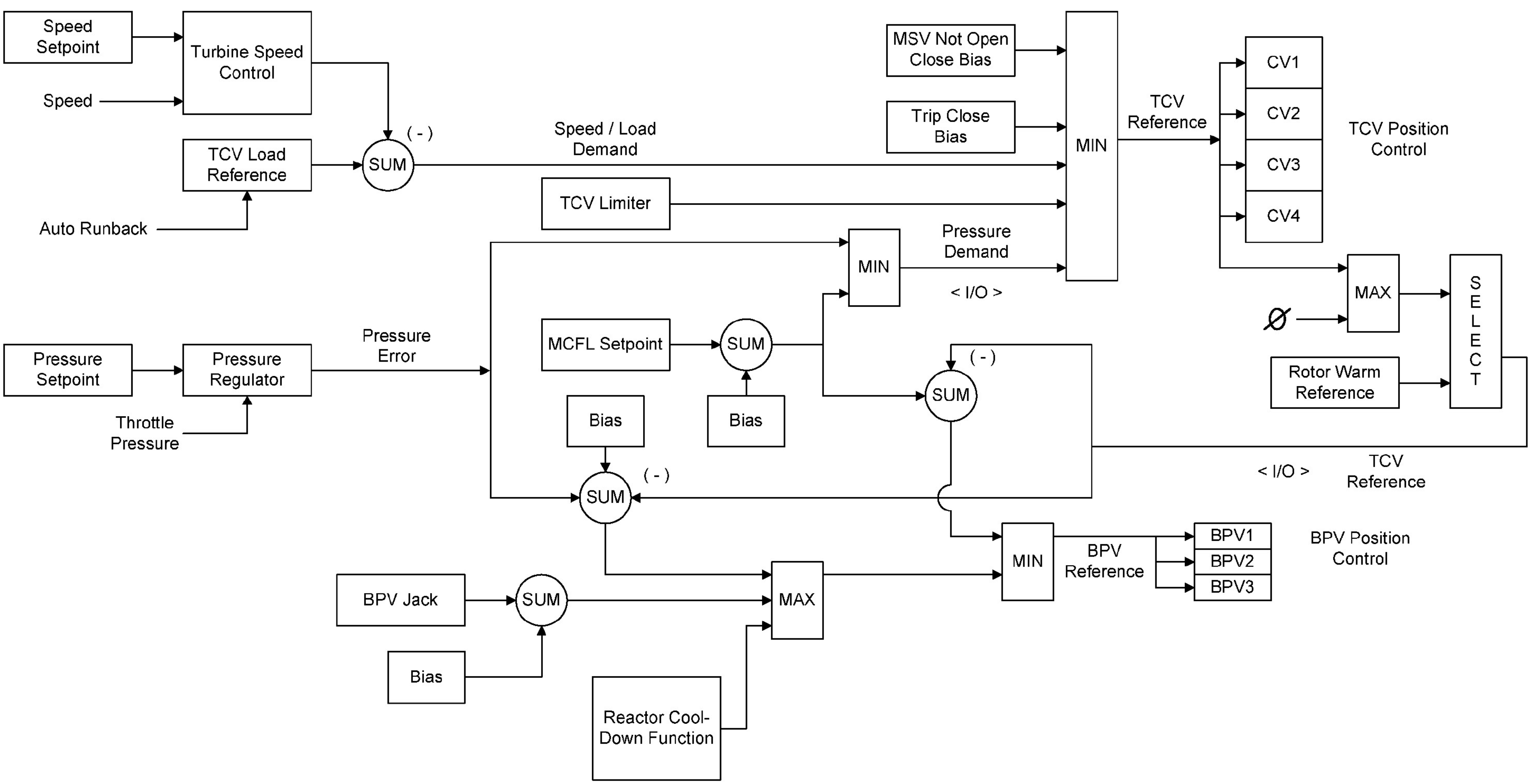
Anticipated operational occurrence analyses were performed for a component failure in the turbine-generator system and are included in HNP-2-FSAR section 15.2.

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. RER 03-254, Reactor Operating Pressure Increase from 1050 psia to 1060 psia, Engineering Evaluations.

Mark VI BWR Functional Diagram



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SIMPLIFIED DIAGRAM OF TURBINE PRESSURE AND SPEED-LOAD CONTROL SYSTEM

FIGURE 7.11-1

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DIAGRAM OF REACTOR PRESSURE, TURBINE SPEED, AND RECIRCULATION FLOW CONTROL SYSTEMS

FIGURE 7.11-2

7.12 PROCESS RADIATION MONITORING

A number of radiation monitors and monitoring systems are provided on process liquid and gas lines that may serve as discharge routes for radioactive materials. These include the following:

- Main steam line radiation monitoring system.
- Air ejector off-gas radiation monitoring system.
- Off-gas vent pipe radiation monitoring system.
- Process liquid radiation monitors.
- Reactor building ventilation radiation monitoring system.
- Post loss-of-coolant accident (LOCA) radiation monitoring system.
- Fission products radiation monitoring system.
- Reactor building vent stack radiation monitor.

The process radiation monitoring system environmental and power supply design conditions are shown in table 7.12-2. These systems are described individually in the following pages.

7.12.1 MAIN STEAM LINE RADIATION MONITORING SYSTEM

7.12.1.1 Safety Objective

The objective of the main steam line radiation monitoring system is to monitor the gross release of fission products from the fuel and, upon indication of such release, to provide an alarm and provide a signal to contain the released fission products.

7.12.1.2 Safety Design Bases

A. The main steam line radiation monitoring system was designed to give prompt indication of a gross release of fission products from the fuel.

B. The main steam line radiation monitoring system is capable of detecting a gross release of fission products from the fuel under any anticipated operating combination of main steam lines.

C. Upon detection of a gross release of fission products from the fuel, the main steam line radiation monitoring system initiates an alarm.

D. Upon detection of a gross release of fission products from the fuel, the main steam line radiation monitoring system isolates the gland seal exhauster and the reactor water sample system, trips the mechanical vacuum pump, and closes the vacuum pump line valve.

7.12.1.3 Description

Four gamma-sensitive instrumentation channels monitor the gross gamma radiation from the main steam lines. The detectors are physically located near the main steam lines just downstream of the outboard main steam line isolation valves in the space between the primary containment and secondary containment walls. Two of the channels are powered from one reactor protection system (RPS) bus, and the other two channels are powered from the other RPS bus.

A function of the main steam line radiation monitors is to detect a release of activity from the reactor that is great enough to alarm and isolate at settings such that doses are within guideline regulations (10 CFR 50.67). These settings are established on activity generated from the postulated design basis control rod drop accident (CRDA).

There are four monitors located in the steam tunnel. The monitors are arranged so that, for a particular level of activity, the reading is approximately the same regardless of which steam line has the activity. The monitors' logic is one-out-of-two twice. Thus, there is still a valid signal with one failure.

The dose to the monitors depends on the activity in the tunnel. Whether that activity is in one line or all four, if it is great enough to cause a significant offsite dose, it will be sufficient to trip the monitors.

All four main steam line radiation monitors are separated from each other by housing them in four isolated bays (one monitor per bay) of panel H11-P606.

The outputs for the recorders and annunciators are grouped together and wired to their respective destinations. The signal for the recorder is tapped across a 1-KΩ resistor of a 10-KΩ divider string which is driven by an operational amplifier. Shorting the recorder output will cause the 1-KΩ resistor to be shorted. This means that the recording level will reach zero, but the operational amplifier will not be prevented from sending the correct signal to the trip circuits because the amplifier is still seeing 9 kW at the recorder output string.

The above is true even if more than one recorder output is shorted. Each monitor has four independent short-circuit proof trip circuits for R_{HH}, R_H, R_L, and inoperable, and the annunciator is connected in fail-safe mode. Shorting any trip output will not affect other independent trip circuits, but will cause its own annunciation because of the fail-safe operating mode. This is true even if more than one annunciator circuit is shorted.

It should be pointed out that the main steam line radiation monitors are not the only instrumentation available for containment isolation. Flux monitors in the core will scram the reactor if the core flux is above preset levels. The series of radiation monitors on the off-gas system will provide certain alarms and eventual isolation to keep the radiological effects offsite to well within dose limits.

When a significant increase in the main steam line radiation level is detected, alarm signals are transmitted to the main control room (MCR), the gland seal exhauster and the reactor water sample system isolates, the mechanical vacuum pump trips, and the vacuum pump line valve closes.

The assumed fission product inventories and release rates from failed fuel rods are discussed in HNP-2-FSAR section 15.3.

NEDO-10174, May 1970, discusses the question of flow blockage and its effects.

The correlation of fission product release with the size and type of cladding defect is very complex. Consequently, an average defect would be used for calculational purposes, based on empirical results for a total release from an observed number of defects. Refer to the response to Comment 9.4.2 of the Third Supplement to the Brunswick 1 and 2 Preliminary Safety Analysis Report (PSAR). The response to Comment 7.5 of the Fourth Supplement to the Brunswick 1 and 2 PSAR discusses the activity reaching the monitors and the transport time involved.

The background activity at the detectors is very much a function of the previous core operation in terms of the accumulated cladding defects and activity in the coolant from other sources. Discussion of the ability of the detectors to indicate a further precipitate fuel failure relative to background is given in the responses to Comments 3.1 and 7.5 of the Fourth Supplement to the Brunswick 1 and 2 PSAR.

Further discussion of the estimated time from failure to the attainment of setpoint signal for the various systems is given in subsection 7.12.6, which also relates setpoint signal to numbers of failed fuel rods.

The circuitry which shuts off the main condenser mechanical vacuum pump and closes the valve is redundant up to, but excluding, the final circuit breaker.

In view of the limited plant operating periods, which may call for operability of this isolation mode, the reliability is considered to be adequate, particularly when related to the radiological consequences as described below.

The high radiation alarm setting is selected so that a high radiation alarm results from the fission products released in the design basis CRDA. The selected setting is enough above the background radiation level in the vicinity of the main steam lines that spurious alarms are avoided at rated power. However, the setting is low enough that the monitors can respond to the fission products released during the design basis CRDA, which occurs at a low steam flow condition.

Each monitoring channel consists of a gamma-sensitive ion chamber and a log radiation monitor. Capabilities of the monitoring channel are listed in table 7.12-1. Each log radiation monitor has two trip circuits. One trip circuit comprises the upscale trip setting, 3 x background, that isolates the gland seal exhauster, closes the reactor water sample valves, trips the mechanical vacuum pump, and closes the vacuum pump line valve. The other trip circuit is a downscale trip that actuates an instrument trouble alarm in the MCR. An upscale alarm setting, 1 1/2 x background, actuates an alarm in the MCR before the gland seal exhauster and reactor water sample valve isolations, and the mechanical vacuum pump trip. The output from each log radiation monitor is displayed on a 6-decade meter in the MCR.

A multichannel paperless recorder is used to record the outputs from the four monitoring channels.

The trip circuits for each monitoring channel operate normally energized so that failures in which power to monitoring components is interrupted result in a trip signal. The environmental capabilities of the components of each monitoring channel are selected in consideration of the locations in which the components are to be placed.

7.12.1.4 Safety Evaluation

The description of the main steam line radiation monitors indicates how the system is capable of initiating alarms, isolating the reactor water sample system and the gland seal exhauster, tripping the mechanical vacuum pump, and closing the vacuum pump line valve. In HNP-2-FSAR chapter 15.3, Safety Analysis, it is shown that the amount of fuel damage and the amount of fission product release involved in this accident are relatively small.

7.12.1.5 Inspection and Testing

A built-in, adjustable current source is provided for test purposes with each log radiation monitor. Routine verification of the operability of each monitoring channel can be made by comparing the outputs of the channels during power operation.

7.12.2 AIR EJECTOR OFF-GAS RADIATION MONITORING SYSTEM

7.12.2.1 Power Generation Objectives

The objectives of the air ejector off-gas radiation monitoring system are to indicate when limits for the release of radioactive material to the environs are approached and to effect appropriate control of the off-gas so that the limits are not exceeded.

7.12.2.2 Power Generation Bases

A. The air ejector off-gas radiation monitoring system provides an alarm to operations personnel whenever the radioactivity level of the air ejector off-gas reaches Technical Specifications release limits.

B. The air ejector off-gas radiation monitoring system provides a record of the radioactivity released via the air ejector off-gas line.

C. The air ejector off-gas radiation monitoring system initiates appropriate action in time to prevent exceeding short-term limits on the release of radioactive materials to the environs as a result of releasing the radioactivity contained in the air ejector off-gas.

7.12.2.3 Description

The air ejector off-gas radiation monitoring system specifications are given in table 7.12-1. The off-gas is monitored both before and after the recombiner/carbon bed treatment. The monitoring system used prior to treatment is comprised of two instrument channels monitoring the gases passing through a vertical section of stainless steel pipe which is designed to minimize plateout. A sample is drawn from the off-gas line through the sample chamber by the main condenser suction. The sample system is arranged to give at least a 2-min time delay before the sample is monitored. This time delay allows nitrogen-16 and oxygen-19 activity decay. This reduces the background radiation that the detector would otherwise measure. Each channel consists of a gamma-sensitive ion chamber, a logarithmic radiation monitor that includes a power supply and a meter, and one channel of a multichannel recorder. The monitor and the recorder are located in the MCR.

The monitor has two upscale trip circuits (radiation alarm high-high (RAHH) and radiation alarm high (RAH)) and a downscale trip circuit (radiation alarm low (RAL)). The upscale trips indicate high and high-high radiation, and the downscale trip indicates instrument trouble. Any one trip will give an alarm in the MCR.

The monitoring system used after the recombiner/carbon bed treatment is comprised of two independent instrument channels monitoring gases passing through a sample chamber mounted on a sample rack along with pump, flow measuring and control equipment, check sources, purge equipment, scintillation detectors, and preamplifiers. Each channel is comprised of a detector, a preamplifier, a log count rate monitor including power supply and meter, and one channel of a multichannel recorder. The detectors monitoring the process after treatment are gamma-sensitive, scintillation detectors. The monitors for these channels are 7-decade log count rate monitors located in the control room with three adjustable upscale trip circuits, one downscale trip circuit, and an instrument inoperative trip. The lower level upscale trip RAH is used to close the bypass line and open the treatment line and alarm. The intermediate upscale trip RAHH is used to alarm, and the upper level upscale trip (radiation alarm high-high-high (RAHHH)) in conjunction with the downscale trip RAL is used to isolate the off-gas system outlet and drain valves and alarm.

The carbon vault is monitored for gamma activity with a single instrument channel. The channel includes a sensor and converter, an indicator and trip unit, and a locally mounted auxiliary unit. Power is supplied from one of the power supplies associated with the reactor building ventilation exhaust monitors. The indicator and trip unit is located in the MCR. The channel provides for sensing and readout, both local and remote, of gamma radiation over a range of 6 logarithmic decades (1 to 10^6 mR/h).

The indicator and trip unit has one adjustable upscale trip circuit for alarm and one downscale trip circuit for instrument trouble. The trip circuits are capable of convenient operational verification by means of test signals or through the use of portable gamma sources. Insofar as practical, all components are self-monitoring to the extent that power failure to any component operates the trip circuits.

The air ejector off-gas radiation monitoring system is not a safety system and is not specifically designed to meet the single failure criteria. However, the system itself is designed to provide a certain amount of redundancy which will enhance total plant availability. This redundancy is provided in several ways.

A. The air ejector off-gas radiation monitoring system is composed of two subsystems, the pretreatment off-gas radiation monitor and sampler and the post-treatment off-gas radiation monitors and sampler.

B. The pretreatment monitoring subsystem is a single channel of electronics and sampling which monitors and samples the off-gas effluent prior to the 30-min holdup line. The monitoring channel, which responds to gross gamma, is periodically calibrated in accordance with plant procedures. In addition to the continuous indication, alarms are provided to notify the operator if the radioactive level reaches the average annual release limit and the instantaneous release limit assuming treatment. With the treatment system in operation, the operator would have a minimum of 11 h to manually correct the situation before any release reached the outlet valve assuming the post-treatment monitoring subsystem was completely inoperative. If it was assumed that the treatment system is in the bypass mode, the operator would still have a minimum of 2 h to take appropriate manual action.

C. The post-treatment radiation monitoring subsystem samples the off-gas effluent prior to the outlet valve and is comprised of dual electronic gross radiation monitors and a sampler.

These monitors are also periodically calibrated in accordance with plant procedures. In addition to the continuous indication, each monitor will provide an alarm at the bypass limit, a value of release approximately one-half the average annual value, and either monitor will provide a signal to close the bypass valve and open the treatment valve. A second alarm is provided on each monitor to signal the operator that the average annual release limit is exceeded. A third alarm level is provided which will close the off-gas outlet valve if the instantaneous release limit is reached. The logic of closure is two upscale trips, one upscale, and one or two downscale trips. This logic provides some immunity to subsystem single failures while providing good plant availability.

D. Aside from the off-gas radiation monitoring system, the off-gas vent pipe (stack) radiation monitoring system provides another independent audit of the off-gas effluent release from the plant. In view of all the information available to the operator, it is highly improbable that releases in excess of the allowed limits could occur.

7.12.2.4 Power Generation Evaluation

The air ejector off-gas radiation monitors have been selected with monitoring characteristics sufficient to provide plant operations personnel with accurate indication of radioactivity in the air ejector off-gas. The system provides the operator with enough information to easily control the activity release rate. Sufficient redundancy is provided to allow maintenance on one channel without losing the indications provided by the system.

7.12.2.5 Inspection and Testing

Each channel can be calibrated by analysis of a grab sample.

7.12.3 OFF-GAS VENT PIPE RADIATION MONITORING SYSTEM

See paragraph 11.4.2.8.6 of the HNP-2-FSAR and drawing no. H-16564.

7.12.4 PROCESS LIQUID RADIATION MONITORS

See paragraph 11.4.2.9 of the HNP-2-FSAR and drawing no. H-26012.

7.12.5 REACTOR BUILDING VENTILATION RADIATION MONITORING SYSTEM

See subsection 7.6.3 of the HNP-2-FSAR.

7.12.6 POST LOCA RADIATION MONITORING SYSTEM

See paragraphs 7.6.4.2 and 11.4.2.8.12 of the HNP-2-FSAR. See also drawing no. H-16274.

7.12.7 FISSION PRODUCTS RADIATION MONITORING SYSTEM

See paragraphs 7.6.4.1 and 11.4.2.8.11 of the HNP-2-FSAR. Also, see drawing no. H-16273.

7.12.8 REACTOR BUILDING VENT STACK RADIATION MONITOR

The system consists of a normal-range monitor and an accident-range monitor. The monitoring system measures the activity in the reactor building vent stack prior to discharge to the environment and in doing so, complies with General Design Criterion (GDC) 64. The activity this monitor is designed to detect is due to corrosion and fission products carried with the air from the reactor, turbine, control, and radwaste buildings ventilation systems.

For the normal-range monitor, a continuous representative sample is extracted from the vent stack through an isokinetic probe, and is passed through a paper filter to collect particulates and through an impregnated charcoal filter to collect iodine. The sample then travels through the sampling system which consists of redundant radiation elements, a gaseous monitor and indicator, a flow indicator, a pressure switch that alarms locally on high or low flow, and redundant pumps that return the sample to the reactor building vent stack.

The isokinetic probe is located in the stack in a position where complete mixing has occurred. The sampling system is configured as shown on drawing no. H-16564. Each detector/monitor channel is powered from an essential motor control center. The sampling system is manually initiated and is provided with flow indication, thus assuring proper valving and sampling during releases.

Comparison of reactor building vent stack specification and performance to ANSI N13.10-1974 criteria are as follows:

The HNP-1 normal-range equipment adheres to the guidelines of the subject ANSI Standard, with the following exceptions:

<u>Paragraph 5.3.1.3 - Range</u>

The reactor building vent stack meter monitors in counts/min. There are calibration curves to relate counts/min to $\mu C/cm^3$ instead of having to adjust the meter to read the count in $\mu C/cm^3$ directly for some individual isotope.

Paragraph 5.3.2.1 - Temperature

The temperature range for the HNP-1 equipment is 0 to 55°C (32 to 130°F). ANSI specifies 0 to 60°C.

Paragraph 5.3.2.2 - Pressure

ANSI requires that the pressure range be specified over the range 500 to 800 Torr (760 Torr = 1 atm). The HNP-1 equipment was specified to operate in a normal (atmospheric pressure) environment.

Paragraph 5.3.2.4.2 - Power Variations

ANSI specifies ± 15% voltage and frequency. The HNP-1 equipment meets ± 10% voltage and ± 5 Hz (± 8%) frequency variations.

Paragraph 5.3.2.7 - Background Radiation

The HNP-1 requirement for background radiation is 1 mr/h Co-60 gamma. The ANSI guidelines specify:

A.	SR-90, Y-90	For beta background (0.8 MeV)
B.	Co-60	For gamma background (1.2 MeV)
C.	AmBe	For neutron background (5 MeV)

Part C does not apply, because the reactor building vent stack sampling system is not exposed to neutron background. Also, part A is not applicable, because the instrument is shielded for gamma. Therefore, no beta should get through the shield.

Paragraph 5.4.2 - Range

The range specified by ANSI is 4 decades. The HNP-1 unit has a 5-decade range.

Paragraph 5.4.7.1 - Temperature

The ANSI guideline suggests that there be < 5% change in calibration or response between 0 and 60°C. The HNP-1 general requirement was a 0 to 55°C temperature range with a 2% change allowed for meter accuracy.

Paragraph 5.4.7.3 - Humidity

The HNP-1 unit can operate in 10 to 95% humidity as recommended by ANSI.

Design and administrative controls that preclude specific events that would not be indicated as abnormal operation are discussed in paragraph 11.4.2.8.6 of the HNP-2-FSAR.

The shielded gas monitor has a beta scintillation detector which consists of a beta-sensitive plastic crystal optically connected to a photomultiplier tube. The detector and a preamplifier are mounted in a protective housing which is inserted into a stainless steel chamber. Table 7.12-1 lists the characteristics of the detector. The shielded gas monitor can be disassembled for cleaning or part replacement if the chamber should become contaminated.

The input from the preamplifier in the shielded gas monitor is fed to the log-rate meter indicator located on panel H11-P604. The ratemeter has three alarms which are annunciated in the MCR. These alarms are RAH which warns of radioactivity levels approaching Technical Specifications limits, RAHH which warns of radioactivity levels exceeding Technical Specifications limits, and a circuit failure (downscale trip) alarm. The RAHH contact provides the start signal for the accident-range monitor and trips the normal-range monitor.

A recorder is provided in the MCR. The recorder plots input from both reactor building vent stack gaseous monitors.

The particulate and iodine activity is usually accumulated for one week on filters to accumulate sufficient activity to be detectable. These filters are counted in the counting room to determine the specific radionuclides released and their quantities. The results, together with the gaseous activity recorder, provide a permanent record of the activity released to the environment.

The system provides no control function but is a diagnostic tool which enables the MCR operator to take appropriate action. Power is supplied from an essential motor control center. Arrangement details are shown on drawing no. H-16564.

The accident-range monitor is designed to comply with NUREG-0737, clarification item II.F.1, and with Regulatory Guide 1.97, Revision 2, by providing a high-range, gaseous, effluent monitor for the reactor building vent plenum. (See drawing no. H-16564.) Representative sampling is achieved by passing gaseous releases through high-efficiency particulate air (HEPA) filters before being sampled and discharged to the environment. Such treatment removes most large particulates > 5 μ in diameter. With the effluent stream free of particulates with particle sizes > 5 μ in diameter, any remaining smaller size particulates behave in a manner much like a gas and are essentially independent of the effects of nonisokinetic sampling. [a]

a. ANSI N13.1-1969 and letter to J. T. Beckham (GPC) from J. F. Stoltz (NRC) dated February 8, 1982.

TABLE 7.12-1 (SHEET 1 OF 2)

PROCESS RADIATION MONITORING SYSTEMS CHARACTERISTICS

Monitoring System	Instrument Range[(a)]	Instrument Scale	Upscale Trips per Channel	Downscale Trips per Channel
Main steam line	1-10^6 mr/h	6-decade log	1 1[(c)]	1[(c)]
Air ejector off-gas (before treatment)	1-10^6 mr/h	6-decade log	2[(c)]	1[(c)]
Air ejector off-gas (after treatment)	10^{-1} to 10^6 counts/s	7-decade log	1[(c)] 2	1
Carbon bed vault area radiation	1.0-10^6 mr/h	6-decade log	1[(c)]	1
Off-gas vent pipe				
Normal range	10^{-1} to 10^6 counts/s[(b)]	7-decade log	2[(d)]	1[(c)]
Accident range	5.0 x 10^{-2} μ/Ci/cc to 1.0 x 10^5 μ/Ci/cc			
Liquid processes	10^{-1} to 10^6 counts/s[(b)]	7-decade log	1[(c)]	1[(c)]
Reactor bldg ventilation	0.01 mr/h to 100 mr/h	4-decade log	1	1[(c)]

TABLE 7.12-1 (SHEET 2 OF 2)

Monitoring System	Instrument Range[a]	Instrument Scale	Upscale Trips per Channel	Downscale Trips per Channel
Reactor bldg vent stack				
Normal range	10^{+1} to 10^{6} counts/min	5-decade log	2[d]	1[c]
Accident range	1.0×10^{-3} to 1.0×10^{5} μ/Ci/cc			

a. Range of measurements is dependent on items such as the source geometry, background radiation, shielding, energy levels, and method of sampling.
b. Readout is dependent upon the pulse height discriminator setting.
c. Alarms only.
d. The high-high alarm trips the normal-range monitor and starts the accident-range monitor.

TABLE 7.12-2

PROCESS RADIATION MONITORING SYSTEM ENVIRONMENTAL AND POWER SUPPLY DESIGN CONDITIONS

	Sensor Location		Control Room	
Parameter	Design Center	Range	Design Center	Range
Temperature	25°C	0°C to +60°C	25°C	5°C to +50°C
Relative humidity	50%	20 to 98%	50%	20 to 90%
Power, ac	115 V 60 Hz	±10% ±5%	115 V 60 Hz	±10% ±5%
Power, dc	+24 V -24 V	+22 to +29 V -22 to -29 V	+24 V -24 V	+22 to +29 V -22 to -29 V

7.13 AREA RADIATION MONITORING (ARM) SYSTEM

7.13.1 POWER GENERATION OBJECTIVE

The objectives of the ARM system are to warn of abnormal gamma radiation levels in areas where radioactive material may be present, stored, handled, or inadvertently introduced and to provide information regarding radiation levels at selected locations within the plant.

7.13.2 POWER GENERATION DESIGN BASES

A. The ARM system provides operating personnel with a record and an indication in the main control room (MCR) of gamma radiation levels at selected locations within the various plant buildings.

B. The ARM system provides local indication and alarms where it is necessary to warn personnel of substantial immediate changes in radiation levels. High-radiation levels in any area of the plant activate an annunciator in the MCR.

C. ARMs for criticality monitoring are not provided.

The Nuclear Regulatory Commission granted an exemption from 10 CFR 70.24 relative to the authorization to possess special nuclear material at Plant Hatch.(1) The exemption provides relief from the requirement to install criticality monitors that are not needed. Inadvertent or accidental criticality will be precluded through compliance with the following:

- Technical Specifications.

- Geometric spacing of fuel assemblies in the new fuel storage area and spent fuel storage pool.

- Administrative controls imposed on fuel handling procedures.

- Use of nuclear instrumentation that monitors behavior of nuclear fuel in the reactor vessel.

7.13.3 DESCRIPTION

7.13.3.1 Monitors

The ARM system is shown as a functional block diagram in figure 7.13-1. The channels consist of a combined sensor and converter unit, a combined indicator, audible alarm and trip unit, a shared power supply, and a shared multipoint recorder.

Each monitor has an upscale trip that indicates high radiation and a downscale trip that indicates instrument trouble. These trips sound alarms but cause no control action. The system is powered from the 120-V-ac instrument bus. The trip circuits are designed so that loss of power causes an alarm. The environmental and power supply design conditions are given in table 7.13-1.

The refueling floor zone radiation monitors are not used as an engineered safety feature (ESF) at Plant Hatch. The ESF function was assumed by redundant monitors within the refueling floor ventilation exhaust ducting.

7.13.3.2 <u>Locations</u>

Monitors are located in appropriate areas within the reactor, turbine, and radwaste buildings. Annunciation and indication are provided in the MCR. Some monitors also provide local indication and alarming at the detector.

7.13.4 INSPECTION AND TESTING

An internal trip test circuit, adjustable over the full range of the trip circuit, is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a real trip. All trip circuits are of the latching type and must be manually reset at the front panel. A portable calibration unit is also provided. This is a test unit designed for use in the adjustment procedure for the ARM sensor and converter unit. A cavity in the calibration unit is designed to receive the sensor and converter unit. Located on the back wall of the cylindrical lower half of the cavity is a window through which radiation from the source emanates. A chart on each unit indicates the radiation levels available from the unit for the various control settings.

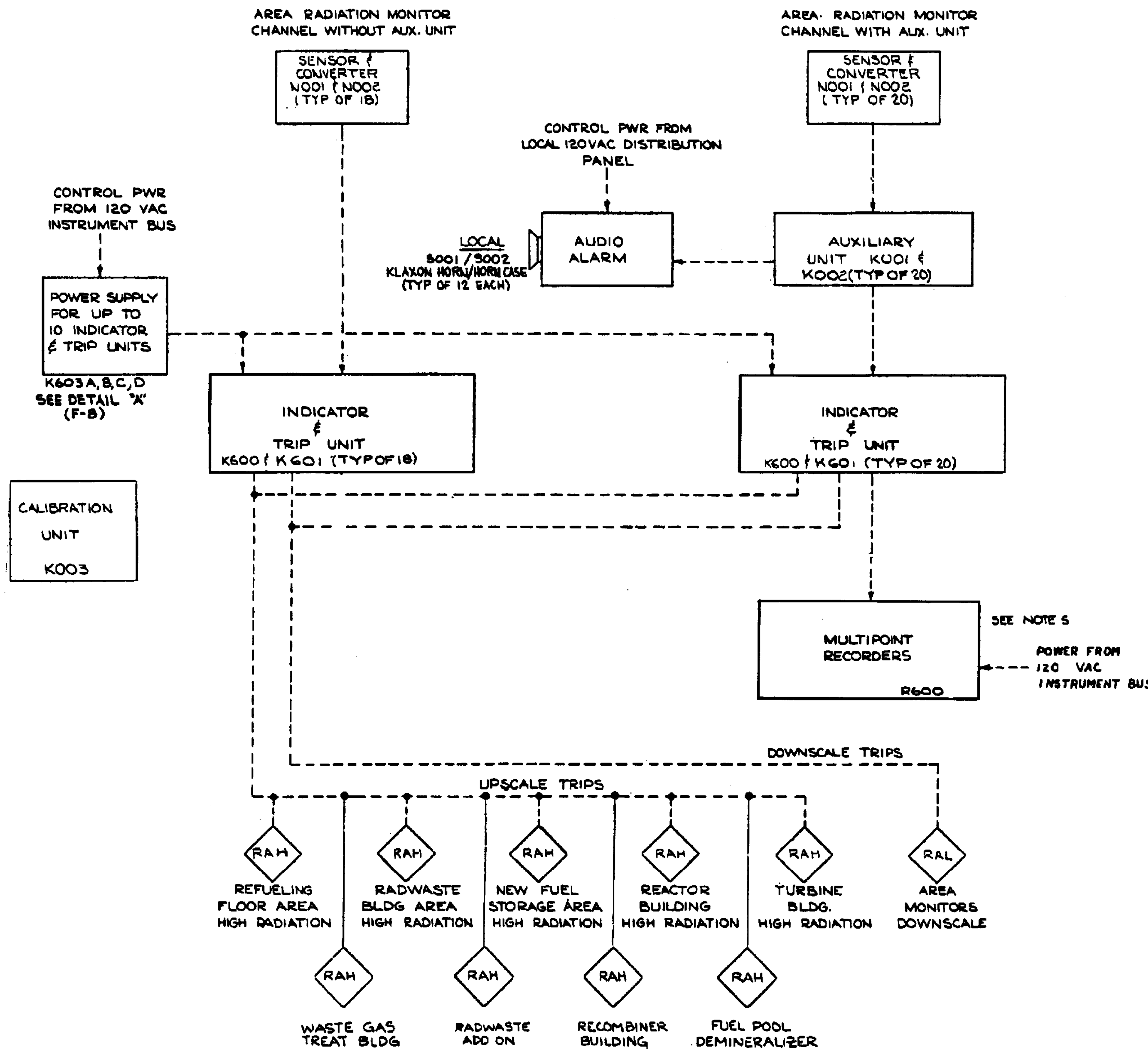
REFERENCES

1. Letter from K. N. Jabbour (Nuclear Regulatory Commission) to J. T. Beckham, Jr. (Georgia Power Company), dated July 31, 1996, regarding exemption from the requirements of 10 CFR 70.24, "Criticality Accident Requirements."

TABLE 7.13-1

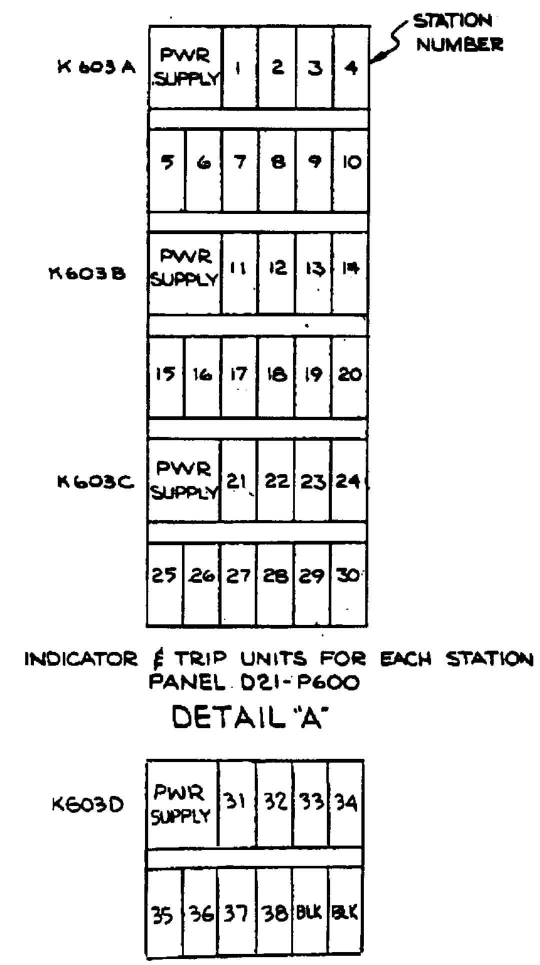
AREA RADIATION MONITORING SYSTEM
ENVIRONMENTAL AND POWER SUPPLY DESIGN CONDITIONS

	Sensor Location		Control Room	
Parameter	Design Center	Range	Design Center	Range
Temperature	25°C	0°C to +60°C	25°C	5°C to +50°C
Relative humidity	50%	20 to 100%	50%	20 to 90%
Power	115 V 50/60 Hz (local alarm only)	± 10% ± 5%	115 V 50/60 Hz	± 10% ± 5%



RANGE	QUANTITY (NOTE 1)		
MR/HR (NOTE 3)	SENSOR & CONVERTER	AUXILIARY UNIT	INDICATOR & TRIP UNIT
.01-100	13	9	13
0.1-1000	0	0	0
$1-10^4$	25	11	25

TABLE 1



NOTES

1. RANGES TO BE CHOSEN BY PURCHASER WITHIN LIMITATIONS OF SCOPE OF SUPPLY.
2. FOR SUGGESTED SENSOR & CONVERTER LOCATIONS REFER TO DESIGN SPECIFICATION.
3. ADDITIONAL RANGES OF $10 - 10^8$, $10^{-2} - 10^4$, AND $1 - 10^6$ MR/HR ARE AVAILABLE BUT ARE INCOMPATIBLE WITH THE 4-DECADE RECORDER SUPPLIED.
4. CHANNEL CALIBRATED BY USE OF CALIBRATION UNIT X003
5. RECORDERS ARE LOCATED IN PROCESS RADIATION RECORDER VERTICAL BOARD.

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AREA RADIATION MONITORING SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.13-1

7.14 PROCESS COMPUTER SYSTEM

See subsection 7.6.8 of the HNP-2 FSAR.

7.15 (Deleted)

7.16 EQUIPMENT QUALIFICATION PROGRAM

On May 23, 1980, the Nuclear Regulatory Commission (NRC) issued a commission memorandum and order (CLI-80-21) which required the licensee to ensure that all Class 1E equipment meets the requirements of the NRC Division of Operating Reactors (DOR) guidelines if the equipment was installed before May 23, 1980. If installed after May 23, 1980, Class 1E equipment must meet the requirements of NUREG-0588, Category I.

Subsequently, the NRC issued Rulemaking 10 CFR 50.49 on February 22, 1983, concerning environmental qualification of electric equipment important to safety. The rule superseded the May 23, 1980, order and required that all equipment installed after February 22, 1983, be upgraded from the DOR guidelines unless there are "sound reasons to the contrary." The acceptable "sound reasons to the contrary" can be found in Regulatory Guide 1.89, Revision 1. Current information regarding equipment qualification is maintained in the Plant Hatch Central File for the Environmental Qualification of Safety-Related Equipment.

Many of the analyses confirming the environmental qualification of safety-related equipment meet the definition of a time-limited aging analysis pursuant to 10 CFR 54.3. (See HNP-2-FSAR subsection 18.1.3 and section 18.5 for additional information.)

7.16.1 OBJECTIVE OF EQUIPMENT QUALIFICATION PROGRAM

The objective of the equipment qualification program is to assure, through testing and/or analysis, that the Class 1E equipment located in potential harsh environments shall perform its safety function when exposed to (and subsequent to exposure) normal, abnormal, and accident environmental conditions.

7.16.2 DESCRIPTION OF EQUIPMENT QUALIFICATION PROGRAM

7.16.2.1 Equipment Identification

Table 7.16-1 lists the systems that are required to mitigate the consequences of a loss-of-coolant accident (LOCA) or high-energy line break (HELB).

The systems listed in table 7.16-1 were reviewed, and a list of Class 1E equipment required to mitigate the consequences of a LOCA or HELB, and located in the harsh environment that it is required to mitigate was established from this review. The list of specific equipment is provided in the Plant Hatch Central File for the Environmental Qualification of Safety-Related Equipment.

7.16.2.2 System Component Evaluation Worksheets

System component evaluation worksheets, as shown in figure 7.16-1, were developed for each piece of equipment identified in paragraph 7.16.2.1. A description of the system component evaluation worksheets is provided in section C.1 of the Georgia Power Company response to IE Bulletin 79-01B, and individual sheets are provided in the Central File.

7.16.2.3 Accident Profiles

Table 7.16-2 lists the various locations within the plant for which a LOCA or HELB temperature profile has been developed. The specific temperature profiles are provided in the Central File.

7.16.2.4 Procurement of New Equipment

All new equipment, which falls under the scope of 10 CFR 50.49, is purchased to meet that requirement. In general, as part of that requirement, new equipment is evaluated against the worst-case environmental profiles through which the equipment must function. These profiles are provided in the central file. For the applicable equipment inside containment, the evaluation is performed against the composite profile provided in figure 7.16-2. This composite profile was developed using the worst-case guillotine break inside containment and the plant-specific main steam line break (MSLB) analysis developed by General Electric in NSEO-52-0583, dated June 1983. A detailed explanation of that analysis is provided in the HNP-2-FSAR. This analysis was developed using the guidelines of NUREG-0588. For equipment inside containment that cannot meet the composite profile, an evaluation against the individual profiles may be performed.

Additionally, table 7.16-7 is provided to describe current plant general area environmental conditions associated with safety-related Class 1E equipment.

7.16.3 QUALIFICATION DOCUMENTATION

The NRC issued an order on October 24, 1980, (clarified in Rulemaking 10 CFR 50.49) which required the licensee to establish a documentation file for the equipment identified in paragraph 7.16.2.1. All the documentation required to support qualification (test reports, test plans, correspondence, etc.) is contained in the Central File, or in the Plant Hatch Document Control System (Maintenance Work Orders, Certification of Conformance, etc.), which are located at the Hatch Nuclear Plant.

7.16.4 SEISMIC QUALIFICATION

7.16.4.1 General Seismic Qualification

The reactor protection system (RPS), engineered safety feature circuits, and the emergency power systems are designed to withstand and perform their functions during an operating basis earthquake (OBE) and a design basis earthquake (DBE). This qualification has been ascertained by either analytical techniques, vibration testing techniques, or a combination of the two techniques.

Specifications, included with each purchase order, specify that all the equipment identified as Class 1 shall meet the specification titled "Seismic Requirements for Class 1 Instrumentation." The latter specification requires the vendor to prove by test and/or analysis that the equipment will resist the horizontal and vertical g forces which the equipment is expected to endure while performing its function. The vendor must submit his test procedures and/or his analysis methods for the buyer's approval. The vendor must submit the test results and the analysis for the buyer's approval as a condition of acceptance of the equipment for shipment.

The documentation of the successful completion of qualification tests for each type of equipment where required are retained by the vendor. Quality control and assurance records and documents required to be located at the jobsite are filed with other applicable documents so that a complete history of a system and its components are filed together.

The following is a brief description of the instrumentation used in the qualification program:

A. In general, the number of monitoring sensors depends on the size of the supporting structure and on the number and location of safety-related devices. As indicated in table 7.16-3, 5 to 20 sensors were used in the examples given.

   The types of sensors used were fixed accelerometers made by Endevco, and a portable vibration pickup (type 1553A) made by General Radio. The latter was often used to check local areas which showed unanticipated amplifications and which were not adequately covered by the fixed accelerometers.

   The location of the accelerometers depends on the configuration of the structure and the location of safety-related devices. The sensors were usually located as near as possible to critical devices, in the center of unsupported areas, and on the ends of cantilevered devices. One accelerometer was always used to determine the input acceleration.

   The maximum response, as shown on table 7.16-3, was 60 g at a 1.5-g input. This was recorded on the front of a long, slim module which was loosely held in a cantilevered case. A bracing scheme is presently being designed to clamp the module into the case since the high acceleration is caused by the shock of the impact between the case and the module rather than by vibration amplification through the supporting structure.

B. Instruments and equipment were mounted during the testing of panels and cabinets.

C. Concerning supporting structures, tests are run on panels and cabinets at low-acceleration levels to determine the transmissibility of the structure from the input to the devices and equipment mounted on the structure. Tests have shown that the transmissibility remains essentially constant with acceleration level; therefore, the accelerations at the devices for other acceleration inputs can be determined without repeating the test at the higher levels. The low-level tests were run over a frequency range of 5 to 33 Hz.

In the case of the 9-14 panel (power range monitor), a slightly different approach was used. Since the subsystem is completely contained in one structure (cabinet), it was feasible to test the structure and its contents in an operating mode. In this case, the acceleration input was run over the full frequency range of 5 to 33 Hz at increasing levels until failure occurred at 1.5 g.

Concerning instruments and equipment, tests were run on these devices by first vibrating them at low-acceleration levels (0.1 g) from 5 to 33 Hz and determining whether resonances existed. The determination was made by visual and audible observation. If resonances were observed, the device was tested at the resonant frequencies at increasing acceleration levels until either failure occurred or the capability of the shaker was reached. If no resonances were observed, the devices were tested at 33 Hz at ever increasing levels of acceleration until either malfunction occurred or the capability of the shaker was reached. The test was run at 33 Hz since that allowed the use of the maximum acceleration capability of the shaker which was displacement limited. This is justified by the fact that since no resonance existed, the device can be considered a rigid body (until failure occurs).

D. Analyses were not used for determination of the amplitude of the device input forcing function. The design approach is based on seismic testing related to a given floor movement.

E. As discussed in paragraph C, if resonances were discerned, the devices are tested to malfunction at those resonances. If resonances were not discerned, the malfunction limit is determined at 33 Hz. The maximum useable g level listed in table 7.16-4 is the malfunction level as determined by test. In addition to these tests, most devices were subjected to a vibration endurance test which was a sweep of ~ 7 min at 1.5 g from 5 to 33 Hz.

7.16.4.2 Qualification of GE-Supplied Equipment[a]

Specifications developed in accordance with principles and objectives of Institute of Electrical and Electronics Engineers (IEEE) Standard 344 are applied to all the equipment identified as Seismic Class 1. These specifications require proof by test and/or analysis that the equipment will withstand the horizontal and vertical g forces which the equipment is required to endure while performing its function. The target test values (1.5-g horizontal and 0.5-g vertical over a frequency range of 5 to 33 Hz) were chosen so as to be well in excess of expected floor accelerations at various supporting structures (panels and racks). Individual instruments were subjected to vibration testing to determine maximum accelerations allowable without malfunction as shown in table 7.16-4.

a. See paragraph 7.16.4.4 for a discussion of the analog transmitter trip system (ATTS) qualification.

Results of qualification tests providing evidence of the capability of each type of equipment to fulfill its safety-related function were obtained.

The instrument racks and control consoles furnished by General Electric (GE) for Class 1 function are designed, tested, and verified as capable of withstanding accelerations in excess of those imposed by the building structure at points of attachment. Restraints are in the form of welded stiffeners located such as to obtain the required degree of rigidity and strength. Designs were verified by vibration tests supplemented by analyses as necessary to show absence of resonances below 5 Hz.

Acceleration at the point of attachment for a specific instrument is related to the floor acceleration by the transmissibility of the supporting structure (panel or rack). The racks and panels are designed to have low amplification (close to 1 at frequencies below 10 Hz and not to exceed 2.5 at frequencies between 10 Hz and 33 Hz). The amplification characteristics of each general type of rack or panel design are demonstrated by vibration test supplemented by analysis at the low end of the frequency spectrum (outside the capability of the test equipment).

A panel or rack assembly is conservatively qualified for use where the actual floor acceleration does not exceed the g value obtained by dividing the lowest instrument qualification value by 2.5. However, where the floor response spectrum at the location of the panel and the amplification spectrum (amplification versus frequency) of the panel (or rack) is known, a more accurate qualification limit may be established. Seismic qualification at 1.5-g horizontal and 0.5-g vertical at the point of attachment is sufficient to assure operability of the instrumentation in a worst-case loading situation at any location in the plant.

The small incremental loading contributed by the connecting wiring (given appropriate cable support) is considered to be adequately provided for by the margin contained in the general seismic qualification requirement.

Attachment systems (bolts, clamps, etc.) were demonstrated to be capable of supporting operating instrumentation which they are designed to support during seismic tests without the benefit of additional support normally offered by connections to cables, conduits, and instrument piping.

7.16.4.3 Special Considerations

Condensing chambers, temperature reference columns, and source range monitor and intermediate range monitor (IRM) dry tubes are designed and fabricated in accordance with the applicable piping and/or boiler codes and are required to be inspected by a third party and appropriately code stamped as certification of their compliance. They are also required to be dynamically analyzed with seismic forces superimposed on normal operating loads from system pressure and temperature for purposes of qualification.

Table 7.16-4 lists the maximum usable g levels for which the various types of instrumentation devices in modules were seismically qualified by actual vibration testing.

Control panels, relay panels, and instruments racks were vibration tested and verified to be free from amplification in excess of 2.5 and capable of withstanding 1.5-g minimum horizontal floor acceleration and 0.5-g vertical floor acceleration at the point of attachment.

7.16.4.4 ATTS Seismic Qualification

The ATTS qualification program was designed to meet or exceed the requirements of IEEE 344-1975. A summary of the program is contained in NEDE-22154-1, with details being presented in NEDC-30039-1. Component qualification was accomplished either by type testing, which simulated triaxial motion, or by similarity analysis. The individual devices covered by this program are listed in table 7.18-1, and information relating to the seismic qualification of these devices is contained in table 7.16-5. Table 7.16-6 identifies the control panels and local instrument racks covered by this program.

TABLE 7.16-1

SYSTEMS REQUIRED TO MITIGATE LOCA OR HIGH-ENERGY LINE BREAK

Description	System
Nuclear boiler system	B21
Reactor recirculation (isolation only)	B31
Control rod drive hydraulic system	C11
Reactor protection system	C71
Process radiation monitoring system	D11
Residual heat removal (RHR) system	E11
Core spray system	E21
High-pressure coolant injection (HPCI) system	E41
Reactor core isolation cooling (RCIC) system (isolation only)	E51
Radwaste system (isolation only)	G11
Reactor water cleanup (RWC) system (isolation only)	G31
Primary containment atmosphere H_2 and O_2 analyzer system	P33
Plant service water system	P41
Reactor building closed cooling water system (isolation only)	P42
Drywell pneumatic system (isolation only)	P70
Reactor zone ventilation and refueling floor ventilation system (isolation only)	T41
Standby gas treatment system	T46
Primary containment purge and inerting system	T48
Containment atmosphere cooling system	T47
Remote shutdown system	C82
Torus drainage and purification system (isolation only)	G51
Motor control center	R24
Local motor starters	R27
Reactor building electrical penetration	T52

TABLE 7.16-2

PLANT LOCATIONS WITH LOCA OR HIGH-ENERGY LINE BREAK TEMPERATURE PROFILE

Inside containment

Reactor building el 130 ft

Torus room

RWC heat exchanger room

RWC pump room

Reactor building el 158 ft

Pipe penetration room

RCIC corner room

Reactor building el 185 ft

Reactor building el 203 ft

Pipe chase

Reactor building el 164 ft

HPCI room

TABLE 7.16-3

SUMMARY OF PANEL AND RACK SEISMIC TEST

Panel	Number of Sensors	Location	Maximum Acceleration/ Input Acceleration
9-3	11	10 Front, 1 Inside	1.5 g/1.5 g
9-4	11	10 Front, 1 Inside	1.5 g/1.5 g
9-5	20	20 Front	1.1 g/1.0 g
9-6	11	10 Front, 1 Inside	1.5 g/1.5 g
9-8	11	10 Front, 1 Inside	1.5 g/1.5 g
9-10	9	8 Front, 1 Inside	60 g/1.5 g
9-12	9	8 Front, 1 Inside	60 g/1.5 g
9-14	1	[a]	4.7 g/1.5 g
9-15	11	10 Front, 1 Inside	1.5 g/1.5 g
9-17	11	10 Front, 1 Inside	1.5 g/1.5 g
9-19	9	8 Front, 1 Inside	60 g/1.5 g
9-21	15	15 Front	3.7 g/1.5 g
9-30	11	10 Front, 1 Inside	1.5 g/1.5 g
9-32	15	15 Front	3.7 g/1.5 g
9-33	15	15 Front	3.7 g/1.5 g
9-39	20	20 Front	1.1 g/1.0 g
9-41	20	20 Front	1.1 g/1.0 g
9-42	20	20 Front	1.1 g/1.0 g
Local Racks	5	5 Front	3.0 g/1.0 g

a. Fixed accelerometers were not used. The portable sensor was used to check visual maxima since, in this case, the panel contained a complete subsystem and was tested in an operating condition with failures monitored rather than acceleration levels.

TABLE 7.16-4 (SHEET 1 OF 4)

INSTRUMENTATION SEISMIC QUALIFICATION SUMMARY

Equipment Description	Maximum Usable g Level Horizontal (g)	Vertical (g)	Remarks
Voltage preamplifier	8.5	8.5	
TIP[a] ball valve	25	25	
IRM detector	> 1.5	> 1.5	Maximum not determined
Reactor level switch (Yarway) snap acting	10	10	
Temperature control switch	12	12	
Contactor (GE CR 105)[g]	12	12	
Indicator trip unit GE-MAC	15	15	
Power range monitor fixed incore detectors	> 1.5	> 1.5	Maximum not determined
TIP[a] shear valve assembly	10	10	
Timer (series 650)	9	9	
Temperature switch (Fenwal)	4	4	
Pressure transmitter	10	12	
Flow switch	4	10	Operational spares RHR minimum flow bypass for remote shutdown
Pressure switch	11	11	Recirculation pump discharge
Flow switch (standby liquid flow)	15	15	
Flow converter	15	15	

TABLE 7.16-4 (SHEET 2 OF 4)

Equipment Description	Maximum Usable g Level Horizontal (g)	Maximum Usable g Level Vertical (g)	Remarks
Flow auxiliary unit	11	11	
SRM	3	15	
IRM (dc)	1.5	0.5	
Power supply (20 V dc)	1.5	0.5	
IRM	3	15	
Sensor converter	15	15	
Pressure switches	15	15	Operational spares
Switch (oiltight)	20	20	
Pressure switch (drywell)	15	15	Operational spares
Pressure switch	15	15	Main steam low pressure
Pressure switch	10	10	Operational spares
Pressure switch (drywell)	15	15	Operational spares
Pressure switch	2	2	
Relay (CRI20A)	12	12	
Relay (HFA)	4	10	
Relay (HGA)	6[b]	5	
Relay (CR2820)	25	25	Time delay
Relay (CR120K)	25	25	
Relay (CR120KT)	12	12	Time delay
Switch (SBM)	25	25	

TABLE 7.16-4 (SHEET 3 OF 4)

Equipment Description	Maximum Usable g Level Horizontal (g)	Maximum Usable g Level Vertical (g)	Remarks
IRM range switch	8.5	8.5	
Thermocouple selection switch	25	25	
Switch oiltight (CR2940)	20	20	
IRM trip auxiliary	12	12	
Scram solenoid fuse panel	10	10	
Fuse	15	15	
Gamma chamber	1.5	0.5	
Controller	5	5	
Manual loading station	2	2	
Millivolt converter	3	3	
Pressure transmitter (types 553 and 551)	2	2	
Flow transmitter	2	2	
Pressure transmitter (type 555)	12	12	
Dual alarm unit	5	5	
Proportional amplifier (flow summer)	3	3	
Square root converter	11	11	
GE-MAC power supply	11	11	
LPRM[c] page	1.5	0.5	
APRM[d] page	1.5	0.5	

TABLE 7.16-4 (SHEET 4 OF 4)

Equipment Description	Maximum Usable g Level Horizontal (g)	Maximum Usable g Level Vertical (g)	Remarks
ICPS[e] page	1.5	0.5	
RBM[f] page	1.5	0.5	
APRM[d] system	1.5	0.5	

a. Traversing incore probe.
b. Except for a normally closed contact on a deenergized relay, there are no applications to this relay arrangement which can negate a safety function.
c. Local power range monitor.
d. Average power range monitor.
e. Ion chamber power supply.
f. Rod block monitor.
g. Power relays on the RPS which interrupt the scram pilot solenoids were replaced with GE series CR 305.

TABLE 7.16-5

CLASS 1E EQUIPMENT COMPRISING THE ATTS

Component	Manufacturer	Primary Class 1E Function	Environment[b]	Seismic Qualification Level	Resonant Frequency[c] (Hz)
Pressure transmitter	Barton	Provide current output response to pressure input	Reactor building	(d)	----
Differential pressure transmitter	Barton	Provide current output response to differential pressure input	Reactor building	(d)	----
Pressure transmitter	Rosemount[a]	Provide current output response to pressure input	Reactor building	(e)	----
Differential pressure transmitter	Rosemount[a]	Provide current output response to differential pressure input	Reactor building	(e)	----
Resistance temperature detector (RTD)	Weed	Provide resistance output response to temperature input	Reactor building	(f)	----
Pressure switch	PCI	Provide contact transfer at pressure trip point	Drywell	(f)	----
Trip units (master, slave, RTD, differential voltage)	GE	Provide trip function at the process variable trip point	Control room	(g)	----
Relay	Agastat	Contact transfer in response to trip unit trip	Control room	(g)	----
Voltage converter	Datametrics	Provide power to ATTS cabinets and instrument loops	Control room	(g)	----

a. The Rosemount transmitters are also used in other applications.
b. For service environments, see tables 4-1 through 4-3 of NEDE-22154-1.
c. No resonant frequencies less than or equal to 33 Hz were identified for any of the devices.
d. See figure 4-12 of NEDE-22154-1. The horizontal qualification levels for these devices are equal to half the acceleration levels defined in figure 4-12. This reduction is employed to account for the simulation of triaxial testing.
e. The Rosemount transmitters, which were not qualified as a part of the original ATTS qualification program, are qualified to seismic levels that exceed the seismic requirements at the transmitter location.
f. See figure 4-11 of NEDE-22154-1. The horizontal qualification levels for these devices are equal to half the acceleration levels defined in figure 4-11. This reduction is employed to account for the simulation of triaxial testing.
g. See figures 4-5 and 4-6 of NEDE-22154-1 for the seismic qualification levels for the cabinets in which these devices are mounted.

TABLE 7.16-6 (SHEET 1 OF 2)

SEISMIC QUALIFICATION TEST SUMMARY FOR ATTS CONTROL PANELS AND LOCAL RACKS

Control Panel No.	Description	Type	Class 1E Equipment Description	Comments
H11-P921	RPS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P922	RPS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P923	RPS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P924	RPS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P925	Emergency core cooling system (ECCS) cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P926	ECCS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P927	ECCS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P928	ECCS cabinet	Control panel	Agastat relays, GE trip units Datametric voltage converters	Seismic test completed
H11-P016	HPCI leak detection	Local rack	Process transmitters	Seismic test completed
H11-P035	RCIC leak detection	Local rack	Process transmitters	Seismic test completed
H11-P036	HPCI leak detection	Local rack	Process transmitters	Seismic test completed
H11-P038	RCIC leak detection	Local rack	Process transmitters	Seismic test completed
H21-P402	RWC system	Local rack	Process transmitters	Seismic test completed
H21-P404A	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P404B	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P404C	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P404D	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P405A	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P405B	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed

TABLE 7.16-6 (SHEET 2 OF 2)

Control Panel No.	Description	Type	Class 1E Equipment Description	Comments
H21-P405C	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P405D	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P409	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P410	RPV water level and pressure	Local rack	Process transmitters	Seismic test completed
H21-P414A	HPCI system	Local rack	Process transmitters	Seismic test completed
H21-P414B	HPCI system	Local rack	Process transmitters	Seismic test completed
H21-P415A	Main steam line flow	Local rack	Process transmitters	Seismic test completed
H21-P415B	Main steam line flow	Local rack	Process transmitters	Seismic test completed
H21-P417A	RCIC system	Local rack	Process transmitters	Seismic test completed
H21-P417B	RCIC system	Local rack	Process transmitters	Seismic test completed
H21-P425A	Main steam line flow	Local rack	Process transmitters	Seismic test completed
H21-P425B	Main steam line flow	Local rack	Process transmitters	Seismic test completed
H21-P434	HPCI system	Local rack	Process transmitters	Seismic test completed
H21-P437	RCIC system	Local rack	Process transmitters	Seismic test completed

TABLE 7.16-7

AREA ENVIRONMENTAL CONDITIONS FOR EQUIPMENT QUALIFICATION[1]

Location	Temperature (°F)		Pressure (psia)		Humidity (%)		Radiation
	Normal	DBE (max)	Normal	DBE (max)	Range	DBE	(Rads)[2]
Containment (drywell)	(6)	330	16.45	65.5	40-90	100	1.22×10^{8}
Reactor bldg el 203 ft	100	190	14.70	15.4	50-80	100	1.90×10^{5}
Reactor bldg el 185 ft	100	205	14.70	15.4	50-80	100	1.90×10^{5}
Reactor bldg el 164 ft	100	257	14.70	16.5	50-80	100	2.41×10^{3} [3]
Reactor bldg el 158 ft	100	210	14.70	15.4	50-80	100	2.51×10^{6}
Reactor bldg el 130 ft	100	213	14.70	16.7	50-80	100	2.37×10^{6}
RWC heat exchanger	110	217	14.70	17.3	50-80	100	9.93×10^{6}
RWC pump room	110	218	14.70	17.3	50-80	100	2.19×10^{5}
Pipe penetration room	120	223	14.70	19.1	50-80	100	6.77×10^{6}
Pipe chase	120	300	14.70	18.0	50-80	100	1.20×10^{7}
Torus room	120	218	14.70	16.7	50-90	100	1.40×10^{7}
RCIC corner room (SW)	100	295	14.70	15.8	50-90	100	9.85×10^{4}
HPCI room	100	148[4] for 12 h	14.70	14.7[5]	50-90	100	9.85×10^{4}
NE corner room (RHR)	100	215	14.70	15.9	50-90	100	6.15×10^{6}
SE corner room (RHR)	100	148	14.70	14.7	50-90	100	6.15×10^{6}

LEGEND:

RWC - reactor water cleanup
RCIC - reactor core isolation cooling
RHR - residual heat removal
SGTS - standby gas treatment system
HPCI - high pressure coolant injection

NOTES:

1. Individual component equipment qualification is based on environmental conditions specified in the Plant Hatch Central File for the Environmental Qualification of Safety-Related Equipment. The information in this table should be verified before use.
2. Total integrated dose for the area specified (DBA + 60 years, normal dose).
3. Dose excludes SGTS filter room; HNP-1 el 164 ft is an open area.
4. The temperature is based on an HELB outside the HPCI room. An analysis indicates the reactor core decay heat will not produce sufficient steam to drive the HPCI turbine after 12 h.
5. 26.6 psia for isolation equipment only.
6. Temperature varies depending on drywell location.

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EQUIPMENT DESCRIPTION	ENVIRONMENT			DOCUMENTATION REF*		QUAL. METHOD	OUTSTANDING ITEMS
	PARAMETER	SPEC.	QUAL.	SPEC.	QUAL.		
SYSTEM: PLANT ID NO.	OPERATING TIME						
COMPONENT:	TEMP. (°F)						
MANUFACTURER:	PRESSURE (PSIA)						
MODEL NUMBER:	RELATIVE HUMIDITY (%)						
FUNCTION:	CHEMICAL SPRAY						
ACCURACY: SPEC: DEMON:	RADIATION (Rads)						
SERVICE: LOCATION:	AGING						
FLOOD LEVEL ELEV: ABOVE FLOOD LEVEL:	SUBMERGENCE						

*Documentation References:

Notes:

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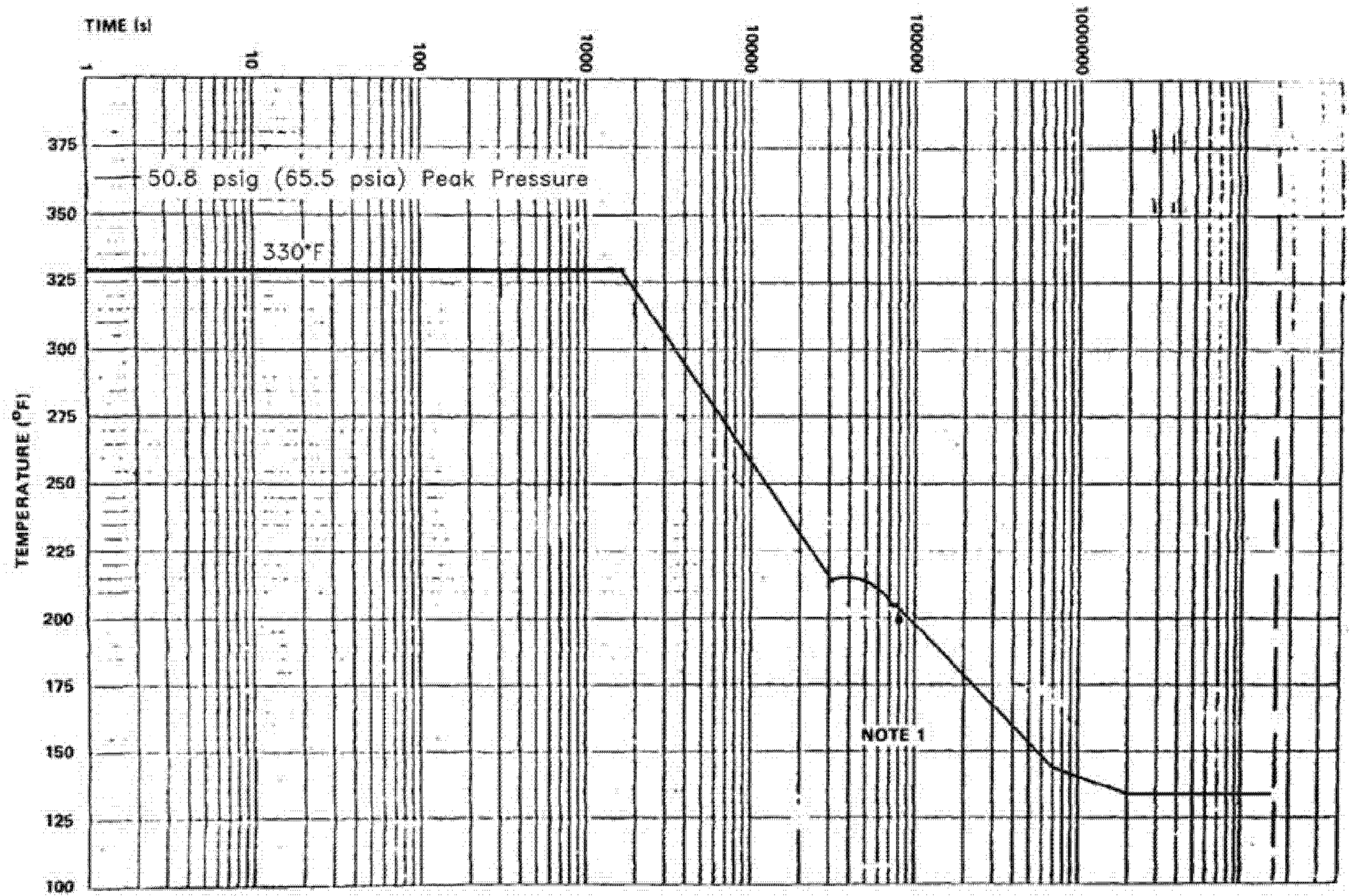
UNIT 1

SYSTEM COMPONENT EVALUATION WORK SHEET

FIGURE 7.16-1



NOTES: 1. The profile after this time is to simulate post-accident operation and may be modified by the vendor to accelerate the aging time based on material aging characteristics.

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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

WORST-CASE ACCIDENT PROFILE FOR EQUIPMENT LOCATED IN CONTAINMENT

FIGURE 7.16-2

7.17 RECIRCULATION PUMP TRIP

See subsection 7.6.10 of the HNP-2-FSAR.

7.18 ANALOG TRANSMITTER TRIP SYSTEM (ATTS)

7.18.1 DESIGN BASES

The ATTS was installed to upgrade instrumentation in the reactor protection system (RPS), primary containment isolation system (PCIS), emergency core cooling systems (ECCSs), and reactor core isolation cooling (RCIC) system. The components replaced as part of the ATTS system function as an integral part of the system in which they are installed and as such, meet all the design bases of that system.

7.18.1.1 Design Features

The ATTS design includes the below listed design features:

A. Each component of the ATTS shall be environmentally qualified for its intended service per the requirements of section 7.16.

B. All components of the ATTS shall be Seismic Category I and qualified per section 7.16.4.4.

C. The ATTS shall reduce the time the RPS logic must be in a half-scram condition due to functional testing or calibrating of a safety trip.

D. The calibration frequency of a primary sensor shall be once per operating cycle.

E. The ATTS shall provide continuous monitoring of sensor loop parameters. To detect primary sensor element drift, a channel check is performed once per operator shift.

F. The ATTS shall be designed to minimize the time required to perform functional tests or to calibrate the trip setpoint.

G. The ATTS shall be designed to minimize the probability of instrument-valving errors and instrument testing-related scrams.

7.18.2 SYSTEM DESCRIPTION

7.18.2.1 General

The ATTS is an all solid-state electronic trip system designed to provide stable and accurate monitoring of process parameters.

The system consists of primary sensors, master trip assemblies, slave trip assemblies, calibration units, card file assemblies, and other accessories.

The process parameters monitored by the ATTS are listed in table 7.18-1.

7.18.2.2 <u>Equipment Description and Design</u>

7.18.2.2.1 Process Sensors

Process parameters are continuously sensed by pressure transmitters, differential pressure transmitters, and resistance temperature detectors (RTDs) which are mounted locally or on instrument racks in the reactor building. Analog signals proportional to the actual process conditions are provided by the process sensors via cables routed to the trip units located in the main control room (MCR).

7.18.2.2.2 Master Trip Units

Each master trip unit is a plug-in, printed-wire assembly designed to accept a 4- to 20-mA signal from a remote transmitter or the input of a three-wire 100-ohm platinum RTD. Each trip unit contains the circuitry necessary to condition these inputs and provide the desired switching functions and analog output signals to slave trip units and other instruments external to the ATTS. The master trip units provide output to energize or deenergize trip relays at any point within the 4- to 20-mA or resistance input signal range. An electrical elementary drawing depicting a typical application is shown in figure 7.18-1. Each master trip unit also contains an isolated panel meter that displays the value of the measured parameters which can be scaled in the units of the process variable. The meter is not considered an integral part of the safety system channel.

Test jacks are provided on each master trip unit face for measurement of actual parameter values. A two-position logic invert switch internal to each trip unit allows for the selection of either a high trip or low trip, thereby allowing the trip relays to be either energized or deenergized during normal operation. The system requirements dictate the position of the logic invert switch.

7.18.2.2.3 Slave Trip Units

The slave trip units are used in conjunction with master trip units when it is desirable to have different setpoints from a common sensor. Each slave obtains its input from an analog output signal of a master trip unit. Up to seven slaves can be driven by a single master trip unit, thus permitting eight different setpoints from a single measured parameter. Unlike the master, there is no direct connection of the slave to a sensor, nor are any analog signals generated by the slave. However, each slave has its own output logic switching function for either high or low trip which is independent of its master or other parallel slaves.

7.18.2.2.4 Differential Voltage Trip Units

The differential voltage trip units receive input from two master trip units. These differential voltage trip units are used for the differential temperature trips in the steam leak detection system; and, similar to a master trip unit, it has a front panel meter to show the value of the measured parameter. The output configuration for a differential voltage trip unit is the same as for a master trip unit.

7.18.2.2.5 Trip Relays

Each master, slave, or differential voltage trip unit is capable of supplying trip relay loads up to 1 A at nominal 25 V-dc. Contacts from these relays provide the necessary logic function for the process variable input. The trip relays provide input to only one division and are not considered an interdivisional isolation device. The trip relays used have four single-pole-double-throw contacts; therefore, the relays will provide any contact logic function that the system requires. Also, the relays are used to provide Class 1E to non-Class 1E isolation for input to the annunciators.

7.18.2.3 Power Sources

Power sources to the ATTS cabinets are supplied from the following buses:

A. The ATTS RPS cabinets are supplied with 120 V-ac power from the RPS buses which are powered by RPS motor generator sets.

B. The ATTS ECCSs cabinets are supplied with 125 V-dc power from the dc buses 1A and 1B which are backed up by the plant service battery system.

Each ATTS cabinet is supplied with two voltage converters which convert 120 V-ac or 125 V-dc to 25 V-dc. The converted voltage has the following design features to assure a highly reliable power supply:

A. Two power sources from different buses listed above feed each ATTS cabinet.

B. Each power source has its own voltage converter in each cabinet.

7.18.2.4 Initiating Circuits

The ATTS senses essential process parameters and generates trip signals which are input to initiating circuits for RPS, PCIS, ECCS, RCIC system, ARI system, and low-low set (LLS) relief logic system. The initiating circuits for which ATTS provides trip signals are discussed in sections 7.2, 7.3, 7.4, 4.7, 3.4.5.4.4, and 7.19, respectively.

7.18.2.5 Logic and Sequencing

The ATTS does not perform any logic or sequencing internal to itself but does provide input for the logic and sequencing of the RPS, PCIS, ECCSs, RCIC system, ARI system, and LLS relief logic system as discussed in sections 7.2, 7.3, 7.4, 4.7, 3.4.5.4.4, and 7.19, respectively.

7.18.2.6 Bypasses, Interlocks, and Alarms

Each master, slave, and differential voltage trip unit has a gross-failure and trip light-emitting diode (LED). The trip LED is illuminated when the setpoint is exceeded, and the gross-failure LED is illuminated when one or more of the following conditions exist:

A. Gross Failure Low

The most important function of the low gross-failure alarm is to sense an open sensor loop; however, some failures within the sensor or trip unit are detected by the low gross-failure detection circuit. After the low gross failure has been cleared, the alarm must be manually reset.

B. Gross Failure High

The primary function of the high sensor is to annunciate a short circuit of the sensor or its loop. Some component failures within the sensor or trip unit are also detected by the high gross-failure detection circuit. After the high gross failure has been cleared, the alarm must be manually reset.

C. Card in Calibration

When any trip unit is selected by the calibration unit and placed in the calibrate mode, the calibrate command signal, which switches the input current from the sensor to the calibration unit, is transmitted from the calibrator to the trip unit, thereby turning on the gross-failure LED. However, unlike the other gross-failure circuitry, the calibrate command signal does not latch the gross-failure output. Therefore, when the card is taken out of the calibration mode, the gross-failure output automatically resets and the annunciator may be immediately cleared.

The trip cards, arranged within a common-card file, are connected to form a series loop between the positive 25-V supply voltage and a normally energized relay coil. Removal of any trip unit within the card file will break the current loop and cause the relay to drop out and annunciate via normally closed contacts wired from the relay to an annunciator in the cabinet.

7.18.2.7 Redundancy, Diversity, and Separation

The redundancy, diversity, and separation requirements for the ATTS are consistent with those of the RPS, PCIS, ECCSs, RCIC system, ARI system, and LLS relief logic system, which are discussed in sections 7.2, 7.3, 7.4, 4.7, 3.4.5.4.4, and 7.19, respectively.

7.18.2.8 Actuated Devices

The ATTS does not directly actuate any devices. Devices are actuated via the RPS, PCIS, ECCSs, RCIC system, ARI system, and LLS relief logic system.

7.18.2.9 Testability

The ATTS is not testable as a system since it is an assemblage of independent instrument loops which must be individually tested.

Each master trip unit provides continuous readout of the transmitter control current via the meter located on the front panel, which is calibrated in terms of the process variable. In addition, an output jack provides a 1 to 5 V-dc signal proportional to the process range being monitored. The operator is able to cross-check the transmitter output currents by comparison with transmitters measuring the same variable and, therefore, can determine whether one of the transmitters is malfunctioning.

Each card file is supplied with a calibration unit whose function is to furnish the means by which an in-place calibration check of the master and slave trip units can be performed. The calibrator contains both a stable and a transient current source. The stable current is for verification of the calibration point of any given channel. The transient current source is used to provide a step current input into a selected channel, such that the response time of that channel can be determined from the trip unit input to any point downstream in the logic, including the final element.

7.18.2.10 Environmental Considerations

The ATTS trip units, relays, voltage converters, and miscellaneous cabinet equipment are located in the MCR and are subjected to only a mild environment.

The transmitters and RTDs which are located in the reactor building, are qualified for the environments associated with any high-energy line break for the areas in which they are located.

Section 7.16 describes the ATTS qualification test results.

7.18.2.11 Operational Considerations

The ATTS is required and designed to operate during normal plant operation and during and after a design basis accident to the extent required by the specific systems to which the ATTS provides input signals.

7.18.3 ANALYSIS

7.18.3.1 Conformance to General Functional Requirements[a]

The ATTS affects those systems to which it provides input on a sensor level but not a logic level. The ATTS instrumentation meets the general functional requirements of the specific systems to which it provides input.

7.18.3.2 Conformance to Specific Regulatory Requirements

The ATTS hardware conforms to the standards and regulations listed in reference 1.

The ATTS installation conforms to the standards and regulations required by the specific systems to which it provides input signals. The standards and regulations are listed in sections 3.4.5.4.4, 4.7, 7.2, 7.3, 7.4, and 7.19.

The trip setpoints/allowable values were developed using the criteria of Regulatory Guide 1.105.

a. The minimum number of operable channels, response time, etc.

REFERENCES

1. "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22154-1, General Electric Company, July 1983.

TABLE 7.18-1 (SHEET 1 OF 6)

ATTS INSTRUMENT LOOPS

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
RPV steam dome pressure high	B21-PT-N078 A,B,C,D	B21-PIS-N678 A,B,C,D	RPS	Scram signal	A,B-H21-P404C,D C,D-H21-P405C,D	H-16063
RPV water level 3	B21-LT-N080 A,B,C,D	B21-LIS-N680 A,B,C,D	RPS	Scram signal, PCIS (groups 2, 6, 10, & 11)	A,B-H21-P404C,D C,D-H21-P405C,D	H-16063
RPV water level 1	B21-LT-N081 A,B,C,D	B21-LIS-N681 A,B,C,D	RPS	PCIS (group 1)	A,B-H21-P404C,D C,D-H21-P405C,D	H-16063
RPV water level 2	B21-LT-N081 A,B,C,D	B21-LS-N682 A,B,C,D[a]	RPS	PCIS (group 5 and secondary containment)	A,B-H21-P404C,D C,D-H21-P405C,D	H-16063
Reactor shroud water level (level 0)	B21-LT-N085 A,B	B21-LIS-N685 A,B	ECCSs	Containment spray permissive	A-H21-P409 B-H21-P410	H-16063
Main steam line A high flow	B21-dPT-N086 A,B,C,D	B21-dPIS-N686 A,B,C,D	RPS	PCIS (Group 1)[b]	A,B-H21-P415A,B C,D-H21-P425A,B	H-16062
Main steam line B high flow	B21-dPT-N087 A,B,C,D	B21-dPIS-N687 A,B,C,D	RPS	PCIS (Group 1)[b]	A,B-H21-P415A,B C,D-H21-P425A,B	H-16062
Main steam line C high flow	B21-dPT-N088 A,B,C,D	B21-dPIS-N688 A,B,C,D	RPS	PCIS (Group 1)[b]	A,B-H21-P415A,B C,D-H21-P425A,B	H-16062
Main steam line D high flow	B21-dPT-N089 A,B,C,D	B21-dPIS-N689 A,B,C,D	RPS	PCIS (Group 1)[b]	A,B-H21-P415A,B C,D-H21-P425A,B	H-16062
RPV pressure low	B21-PT-N090 A,D	B21-PIS-N690 A,D	ECCSs	CS,LPCI	A-H21-P404A D-H21-P405A	H-16063
RPV pressure low	B21-PT-N090 E,F	B21-PIS-N690 E,F	ECCSs	LPCI	E-H21-P404A F-H21-P405A	H-16063
RPV pressure low	B21-PT-N090 B,C	B21-PIS-N690 B,C	ECCSs	CS,LPCI	B-H21-P410 C-H21-P409	H-16063
RPV pressure low	B21-PT-N090 B,C	B21-PS-N641 B,CLAM	ECCSs	LPCI	B-H21-P410 C-H21-P409	H-16063
RPV water level 1	B21-LT-N091 A,B,C,D	B21-LIS-N691 A,B,C,D	ECCSs	CS,LPCI, ADS, diesel[b]	A,C-H21-P404A B,D-H21-P405A	H-16063
RPV water level 2	B21-LT-N091 A,B,C,D	B21-LS-N692 A,B,C,D[a]	ECCSs	HPCI, RCIC	A,C-H21-P404A B,D-H21-P405A	H-16063

TABLE 7.18-1 (SHEET 2 OF 6)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
RPV water level low	B21-LT-N091 A,B,C,D	B21-LS-N694 A,B,C,D[(a)]	ECCSs	ATWS-RPT	A,C-2H21-P404A B,D-2H21-P405A	H-16063
RPV water level 8	B21-LT-N093 A,B	B21-LIS-N693 A,B	ECCSs	HPCI, RCIC	Local	H-16063
RPV water level 3	B21-LT-N095 A,B	B21-LIS-N695 A,B	ECCSs	ADS	A-H21-P404B B-H21-P405B	H-16063
RPV water level 8	B21-LT-N095 A,B	B21-LS-N693 C,D[(a)]	ECCSs	HPCI,RCIC	A-H21-P404B B-H21-P405B	H-16063
Reactor pressure LLS arming permissive	B21-PT-N120 A,B,C,D	B21-PIS-N620 A,B,C,D	ECCSs	LLS	A,C-H21-P404A,B B,D-H21-P405A,B	H-16063
Reactor pressure LLS control	B21-PT-N120 A,B,C,D	B21-PS-N621 A,B,C,D[(a)]	ECCSs	LLS	A,C-H21-P404A,B B,D-H21-P405A,B	H-16063
RPV pressure high	B21-PT-N120 A,B	B21-PS-N642 A,B[(a)]	ECCSs	ATWS-ARI ATWS-RPT	A-H21-P404A B-H21-P405A	H-16063
Reactor pressure LLS control	B21-PT-N122 C,D	B21-PIS-N622 C,D	ECCSs	LLS	C-H21-P404A,B D-H21-P405A,B	H-16063
RPV pressure high	B21-PT-N122 A,B	B21-PIS-N643 A,B	ECCSs	ATWS-ARI ATWS-RPT	A-H21-P404A B-H21-P405A	H-16063
RPV LLS control	B21-PT-N122 A,B	B21-PS-N622 A,B[(a)]	ECCSs	LLS	A-H21-P404A B-H21-P405A	H-16063
Steam tunnel high temperature	B21-TE-N123 A,B,C,D	B21-TIS-N623 A,B,C,D	RPS	PCIS (Group 1)	Local	H-16062
Steam tunnel high temperature	B21-TE-N124 A,B,C,D	B21-TIS-N624 A,B,C,D	RPS	PCIS (Group 1)	Local	H-16062
Steam tunnel high temperature	B21-TE-N125 A,B,C,D	B21-TIS-N625 A,B,C,D	RPS	PCIS (Group 1)	Local	H-16062
Steam tunnel high temperature	B21-TE-N126 A,B,C,D	B21-TIS-N626 A,B,C,D	RPS	PCIS (Group 1)	Local	H-16062
ECCS DIV I SRV actuation	B21-PT-N127 A	B21-PIS-N697 A	ECCSs	SRV Logic	A-H21-P404B	H-16062 & H-16063
ECCS DIV I SRV actuation	B21-PT-N127 A	B21-PS-N697 G,L[(a)]	ECCSs	SRV Logic	A-H21-P404B	H-16062 & H-16063
ECCS DIV II SRV actuation	B21-PT-N127 B	B21-PIS-N697 B	ECCSs	SRV Logic	B-H21-P405B	H-16062 & H-16063

TABLE 7.18-1 (SHEET 3 OF 6)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
ECCS DIV II SRV actuation	B21-PT-N127 B	B21-PS-N697 K,H[(a)]	ECCSs	SRV Logic	B-H21-P405B	H-16062 & H-16063
ECCS DIV I SRV actuation	B21-PT-N127 C	B21-PIS-N697 C	ECCSs	SRV Logic	C-H21-P404C	H-16062 & H-16063
ECCS DIV I SRV actuation	B21-PT-N127 C	B21-PS-N697 F,E[(a)]	ECCSs	SRV Logic	C-H21-P404C	H-16062 & H-16063
ECCS DIV II SRV actuation	B21-PT-N127 D	B21-PIS-N697 D	ECCSs	SRV Logic	D-H21-P405D	H-16062 & H-16063
ECCS DIV II SRV actuation	B21-PT-N127 D	B21-PS-N697 M,J[(a)]	ECCSs	SRV Logic	D-H21-P405D	H-16062 & H-16063
SRV initiation LLS arming logic permissive	B21-PS-N302 A-H, J,K,L	NA	ECCSs	LLS	Local	H-16062
SRV initiation LLS arming logic permissive	B21-PS-N301 A-H, J,K,L	NA	ECCSs	LLS	Local	H-16062
RPV steam dome low pressure permissive	B31-PT-N079 A,D	B31-PIS-N679 A,D	RPS	PCIS (Group 6)	Local	H-16063
Drywell high pressure	C71-PT-N050 A,B,C,D	C71-PIS-N650 A,B,C,D	RPS	Scram signal, PCIS (Groups 2, 10 & 11 secondary containment)	Local	H-16568
RHR pump discharge high pressure	E11-PT-N055 A,B,C,D	E11-PIS-N655 A,B,C,D	ECCSs	ADS	Local	H-16329 & H-16330
RHR pump discharge high pressure	E11-PT-N056 A,B,C,D	E11-PIS-N656 A,B,C,D	ECCSs	ADS	Local	H-16329 & H-16330
RHR pump flow low	E11-dPT-N082 A,B	E11-dPIS-N682 A,B	ECCSs	LPCI	Local	H-16329 & H-16330
Drywell high pressure	E11-PT-N094 A,B,C,D	E11-PIS-N694 A,B,C,D	ECCSs	PCIS (Groups 8 & 9) HPCI, CS[(b)] LPCI, ADS	Local	H-16329 & H-16330
CS pump discharge low flow	E21-dPT-N051 A,B	E21-dPIS-N651 A,B	ECCSs	CS	Local	H-16331

TABLE 7.18-1 (SHEET 4 OF 6)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
CS pump discharge high pressure	E21-PT-N052 A,B	E21-PIS-N652 A,B	ECCSs	ADS	Local	H-16331
CS pump discharge high pressure	E21-PT-N055 A,B	E21-PIS-N655 A,B	ECCSs	ADS	Local	H-16331
HPCI pump high pressure	E41-PT-N050	E41-PIS-N650	ECCSs	HPCI	H21-P414B	H-16332
HPCI pump discharge high flow	E41-dPT-N051	E41-dPIS-N651	ECCSs	HPCI	H21-P414A	H-16332
HPCI pump suction low pressure	E41-PT-N053	E41-PIS-N653	ECCSs	HPCI	H21-P414B	H-16333
HPCI pump suction low pressure alarm	E41-PT-N053	E41-PS-N654[a]	ECCSs	HPCI	H21-P414B	H-16333
HPCI turbine exhaust diaphragm high pressure	E41-PT-N055 A,B,C,D	E41-PIS-N655 A,B,C,D	ECCSs	PCIS (Group 3)	A,C-H21-P434 B,D-H21-P414A	H-16333
HPCI turbine exhaust high pressure	E41-PT-N056 B,D	E41-PIS-N656 B,D	ECCSs	HPCI	H21-P414B	H-16333
HPCI steam line high flow	E41-dPT-N057 A,B	E41-dPIS-N657 A,B	ECCSs	PCIS (Group 3)	A-H21-P016 B-H21-P036	H-16332
HPCI steam line high differential pressure(-)	E41-dPT-N057 A,B	E41-dPS-N660 A,B[a]	ECCSs	PCIS (Group 3)	A-H21-P016 B-H21-P036	H-16332
HPCI steam supply low pressure	E41-PT-N058 A,B,C,D	E41-PIS-N658 A,B,C,D	ECCSs	PCIS (Group 3)	A,C-H21-P016 B,D-H21-P036	H-16332
HPCI torus high water level	E41-LT-N062 B,D	E41-LIS-N662 B,D	ECCSs	HPCI	Local	H-16332
HPCI equipment high ambient temperature	E41-TE-N070 A,B	E41-TIS-N670 A,B	ECCSs	PCIS (Group 3)	Local	H-16333
HPCI pipe room high ambient temperature	E41-TE-N071 A,B	E41-TIS-N671 A,B	ECCSs	PCIS (Group 3)	Local	H-16333

TABLE 7.18-1 (SHEET 5 OF 6)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
RCIC pump discharge high pressure	E51-PT-N050	E51-PIS-N650	ECCSs	RCIC	H21-P417B	H-16334
RCIC pump discharge high flow	E51-dPT-N051	E51-dPIS-N651	ECCSs	RCIC	H21-P417A	H-16334
RCIC turbine exhaust high pressure	E51-PT-N056 A,C	E51-PIS-N656 A,C	ECCSs	RCIC	H21-P417B	H-16335
RCIC steam line high flow	E51-dPT-N057 A,B	E51-dPIS-N657 A,B	ECCSs	PCIS (Group 4)	A-H21-P035 B-H21-P038	H-16334
RCIC steam line high differential pressure (-)	E51-dPT-N057 A,B	E51-dPS-N660[a] A,B	ECCSs	PCIS (Group 4)	A-H21-P035 B-H21-P038	H-16334
RCIC steam supply low pressure	E51-PT-N058 A,B,C,D	E51-PIS-N658 A,B,C,D	ECCSs	PCIS (Group 4)	A,C-H21-P035 B,D-H21-P038	H-16334
RCIC equipment high ambient temperature	E51-TE-N061 A,B	E51-TIS-N661 A,B	ECCSs	PCIS (Group 4)	Local	H-16334
Torus ambient temperature (no trip)	E51-TE-N063 A,B,C,D	E51-TIS-N663[c] A,B,C,D	ECCSs	PCIS (Groups 3 & 4)	Local	H-16335
Torus ambient temperature (no trip)	E51-TE-N064 A,B,C,D	E51-TIS-N664[c] A,B,C,D	ECCSs	PCIS (Groups 3 & 4)	Local	H-16335
Torus differential temperature (high)	NA	E51-dTIS-N665[d] A,B,C,D	ECCSs	PCIS (Groups 3 & 4)	NA	H-16335
Torus high ambient temperature	E51-TE-N066 A,B,C,D	E51-TIS-N666 A,B,C,D	ECCSs	PCIS (Groups 3 & 4)	Local	H-16335
RCIC pump suction low pressure	E51-PT-N083	E51-PIS-N683	ECCSs	RCIC	H21-P417B	H-16335
RCIC pump suction low pressure (alarm)	E51-PT-N083	E51-PS-N684[a]	ECCSs	RCIC	H21-P417B	H-16335

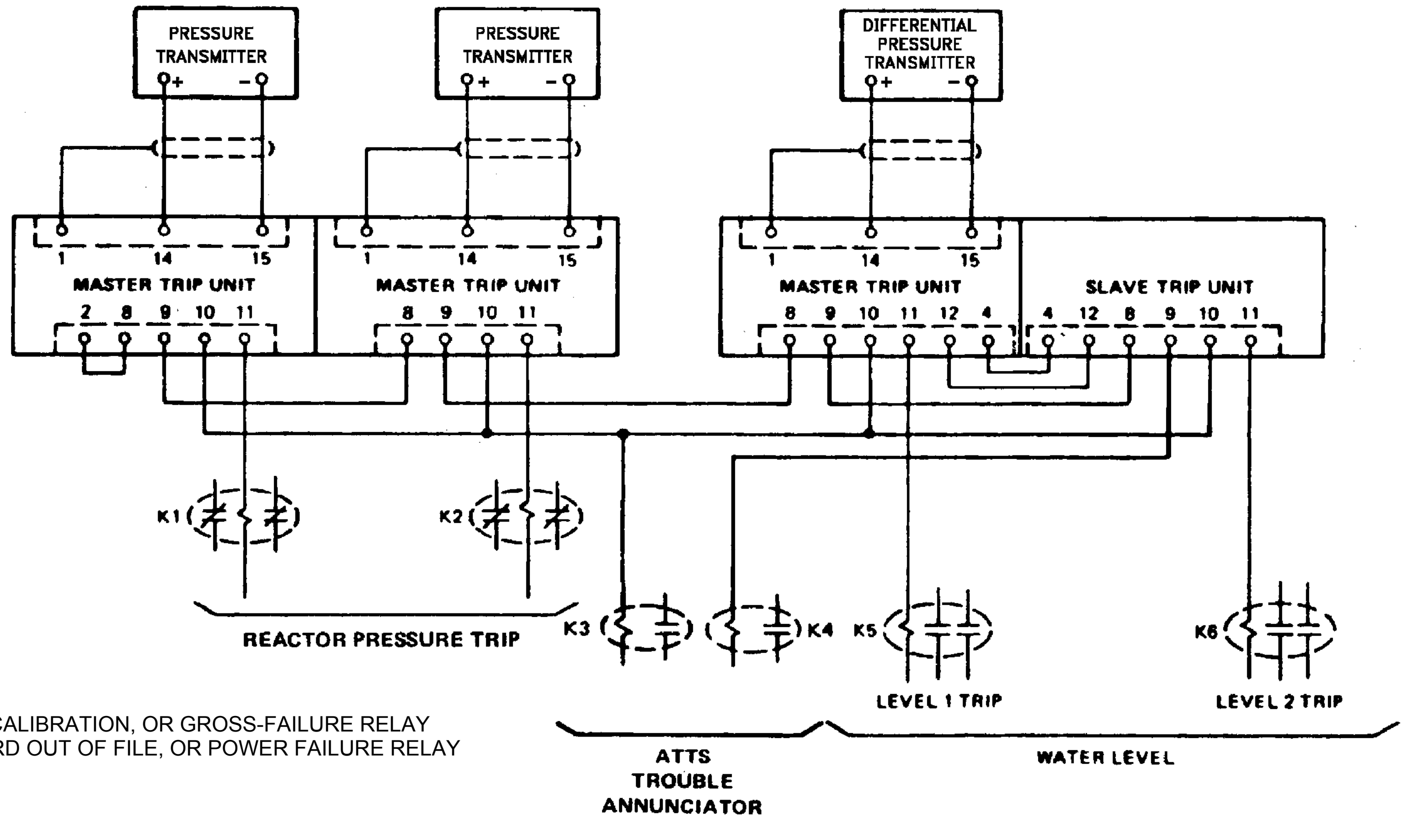
TABLE 7.18-1 (SHEET 6 OF 6)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing No.
RCIC turbine exhaust diaphragm high pressure	E51-PT-N085 A,B,C,D	E51-PIS-N685 A,B,C,D	ECCSs	PCIS (Group 4)	A,C-H21-P417A B,D-H21-P437	H-16335
RWC room temperature inlet (no trip)	G31-TE-N061 A,D,E,H,J,M	G31-TIS-N661[e] A,D,E,H,J,M	RPS	PCIS (Group 5)	Local	H-16188
RWC room temperature outlet high	G31-TE-N062 A,D,E,H,J,M	G31-TIS-N662 A,D,E,H,J,M	RPS	PCIS (Group 5)	Local	H-16188
RWC area ventilation differential temperature high	NA	G31-dTIS-N663[f] A,D,E,H,J,M	RPS	PCIS (Group 5)	NA	H-16188

LEGEND:

ADS - automatic depressurization system
CS - core spray
HPCI - high-pressure coolant injection
LPCI - low-pressure coolant injection
RHR - residual heat removal
RPV - reactor pressure vessel
RWC - reactor water cleanup
SRV - safety relief valve

a. This is a slave trip unit to the first master trip unit listed above it.
b. Actuates control room vent system in pressurization mode.
c. No tripping function serves as input to ΔT trip unit E51-dTIS-N665A,B,C,D.
d. Input to trip unit supplied by E51-TIS-N663A,B,C,D and N664A,B,C,D.
e. No tripping function serves as input to ΔT trip unit G31-dTIS-N663A,D,E,H,J,M.
f. Input to trip unit supplied by G31-TIS-N661A,D,E,H,J,M and N662A,D,E,H,J,M.



K3 = IN CALIBRATION, OR GROSS-FAILURE RELAY
K4 = CARD OUT OF FILE, OR POWER FAILURE RELAY

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UNIT 1

TYPICAL TRIP UNIT/CALIBRATION SYSTEM ELEMENTARY

FIGURE 7.18-1

7.19 LOW-LOW SET RELIEF LOGIC SYSTEM

(See figures 7.19-1, 7.19-2, and 7.19-3.)

7.19.1 DESIGN BASES

The low-low set (LLS) relief logic system is designed in accordance with the following requirements:

- The system shall remain operable in the event of a loss-of-offsite power (LOSP). There shall be no interruption of electric power to the LLS system during a LOSP.
- Single-failure consideration for this system shall include any single active mechanical component or electrical component failure. Battery failure shall also be considered.
- After any single failure, the LLS system shall still perform its intended function; i.e., the required number of LLS valves will operate after any single failure. During normal power operation, no single failure shall cause inadvertent seal-in of the arming logic for more than one LLS valve. No single failure shall cause more than one LLS valve to stick open.
- The pneumatic supply shall be available during a LOSP. Accumulators are used to provide the necessary pneumatic supply.
- The system must be testable during normal plant operation.
- The LLS function shall be assigned to only non-automatic depressurization system (ADS) safety relief valves (SRVs), since the initiation of ADS could cause the valves to reopen before the water level recedes to its original level.
- Manual controls for the LLS system shall be located in the main control room (MCR) and, in addition, at the remote shutdown panels for two of the four valves (one of each division).
- The LLS system must initiate within 1 s after the initial SRV opening, provided reactor pressure is greater than high pressure scram setpoint.

7.19.2 SYSTEM DESCRIPTION

7.19.2.1 Identification and Classification

The LLS relief logic system mitigates the postulated thrust load and shell pressure load concern of subsequent SRV actuations during a small-or intermediate-break loss-of-coolant accident (LOCA) by extending the time between actuations.

The LLS relief logic system, which consists of all Class 1E components, is important to safety.

7.19.2.2 Power Source

Power for the LLS system and the ADS is obtained from the plant station batteries. The power for LLS logic is also obtained from the plant station batteries and is reduced to 25 V-dc by voltage converters located in the analog transmitter trip system (ATTS) control panels. This power source is Class 1E and is available during a LOSP.

In addition to the drywell pneumatic system, accumulators are used for pneumatic supply. The accumulator for each LLS valve is sized for five cycles. This is sufficient, because the worst-case single failure would fail two valves and only 10 cycles total are required.

7.19.2.3 Equipment Design

The LLS system consists of SRV open-close monitors, nuclear boiler pressure instrumentation, a cabinet which houses LLS logic relays, solenoid valves, and pneumatic supply. (Accumulators are part of the pneumatic supply.) The SRV open-close monitors are pressure switches which indicate a SRV opening. The nuclear boiler pressure instrumentation consists of transmitters, trip units, and relays and is a subsystem of the Class 1E analog transmitter trip system (ATTS).(1) This instrumentation is discussed in section 7.18.

The solenoid valves and the air accumulators are equivalent to those for the ADS valves which are Class 1E. All other components, including relays, lights, and cabinets, are Class 1E.

All trip unit and logic relay cabinets are located in the MCR.

7.19.2.3.1 Initiating Circuits

The SRV open-close monitors and the nuclear boiler pressure instrumentation provide pressure trips for the arming pressure permissive and the LLS setpoints. One transmitter and master trip unit provide the arming permissive trip. A slave trip unit and another transmitter/master trip unit provide the two-out-of-two for LLS opening logic and one-out-of-two for reclosing logic. The solenoid valves and the drywell pneumatic system are used to pneumatically operate the valves.

The LLS system is functionally controlled as shown in figure 7.19-1.

7.19.2.3.2 Logic and Sequencing

The LLS logic arms four designated LLS SRVs at their LLS setpoints when any SRV has opened and when concurrent reactor pressure exceeds the scram setpoint. This arming logic is sealed in and annunciated. After arming, nuclear boiler pressure instrumentation controls the solenoid valves so that the LLS SRV valves open and close at their assigned LLS setpoints. Operation continues until manually reset by the control room operator who then controls reactor pressure below the SRV setpoints.

7.19.2.3.3 Bypasses and Interlocks

The logic flow for one LLS division is shown in figure 7.19-1. Tailpipe pressure switches and master trip units control the arming relay. This arming relay is the permissive for the master trip unit and the slave trip unit which control the operation of a SRV.

Since the logic requires two independent signals to arm the system, a single failure will not cause inadvertent arming of more than one LLS valve during normal power operation. As shown in figure 7.19-1, inadvertent arming of the channel A arming relay will not cause an inadvertent arming of the channel C arming relay. Channels B and D are not affected since they are separated from channels A and C.

Failure of a solenoid valve or closing signal for an LLS valve may cause the valve to stick open. The channel arrangement uses separate solenoid valves and pressure sensors to control valve closing. Furthermore, the closing logic of LLS is one-out-of-two which assures a valve closure signal with a single failure.

7.19.2.3.4 Redundancy, Diversity, and Separation

The divisional separation of the LLS design assures that a single active mechanical or electrical component failure or a battery failure will not prevent LLS from performing its intended function.

The system consists of four LLS channels with each channel controlling a separate SRV. The four LLS channels are divided between two separate divisions. The arming logic of the two channels in each division are interlocked, and the two divisions are housed in two separate cabinets. Although all solenoid valves are powered from the ADS cabinet, both divisions of station batteries are used, and each division is separated in accordance with IEEE 384-1974.

7.19.2.3.5 Actuated Devices

The LLS system pneumatically controls the LLS SRVs. The SRVs have a pneumatic actuator which opens the SRV when pressurized air is applied to the actuator. The air supply to the SRV actuators is controlled by a solenoid valve. When the solenoid valve opens or closes, the SRV opens or closes, respectively.

The control logic of the LLS system electrically controls the solenoids associated with the LLS SRVs.

The solenoid valves actuated by the LLS relief logic system may also be actuated manually or by electrical logic backup to the mechanical pressure relief setpoint.

7.19.2.3.6 Testability

The trip units and associated logic are designed to be tested in place, which greatly reduces the required time to perform a surveillance test, therefore, minimizing the time the sensor trip is in the inoperative state. The built-in trip unit calibration system is capable of providing either a stable or transient current that can be used for calibration, functional testing, and time response testing of the trip unit and downstream logic elements.

The nuclear boiler pressure transmitters and the SRV tailpipe pressure switches are tested once per operating cycle when the reactor is out of service for refueling.

7.19.2.4 Environmental Considerations

The LLS system relay cabinets are located in the MCR and are subjected to a mild environment only.

The nuclear boiler pressure transmitters are located in the reactor building and are qualified for environments associated with any high-energy line break in the reactor building.

The solenoid valves and SRV monitors (pressure switches) are located in the drywell and are qualified for a LOCA environment.

The LLS hardware has been seismically qualified by type testing and similarity analysis to criteria that meet or exceed the requirements outlined in IEEE 323-1974 and IEEE 344-1975.[3]

7.19.2.5 Operational Considerations

The LLS relief logic system is automatically initiated for those events involving a SRV blowdown but is not required during normal power operation.

No operator action is required for at least 10 min following initiation. However, the operator may elect to terminate system operation sooner based upon the fact that either SRV blowdown is no longer required or that depressurization is manually controlled.

7.19.3 ANALYSIS

7.19.3.1 Conformance to General Functional Requirements

A plant-specific analysis(2) demonstrated that the LLS relief logic system has the capability of mitigating the postulated loading conditions caused by a small or intermediate break inside the containment. Evaluations(4)(5) show that the design will not have detrimental effects on other safety considerations.

7.19.3.2 Conformance to Specific Regulatory Requirements

The standards and regulations applicable or partially applicable to the LLS relief logic system design are listed in reference 3. The LLS relief logic system conforms, to the maximum practical extent, to the criteria of these standards and regulations.

The system is installed specifically in response to "Safety Evaluation Report, Mark I Containment Long-Term Program, Resolution of Generic Technical Activity A-7," NUREG-0661.

REFERENCES

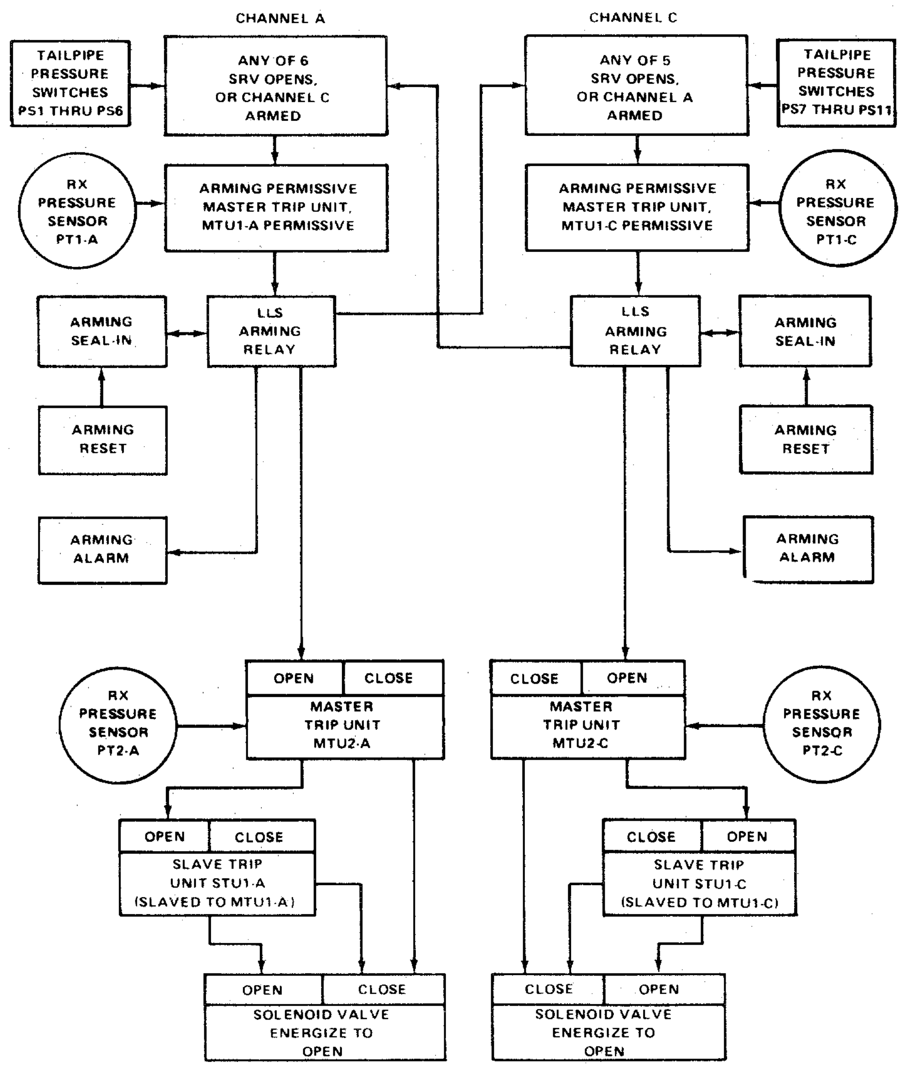
1. "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22154-1, General Electric Company, July 1983.

2. "Plant Unique Analysis Report for E. I. Hatch Nuclear Plant Unit 2 Mark I Containment Long-Term Program," Revision 1, September 1983.

3. "Analog Trip System Qualification Report," NEDC-30039-1, General Electric Company, January 1983.

4. "Low-Low Set Logic and Lower MSIV Water Level Trip for BWRs with Mark I Containment," NEDE-22223, General Electric Company, September 1982.

5. "Low-Low Set Relief Logic System and Lower Water Level Trip for Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22224, General Electric Company, December 1982.



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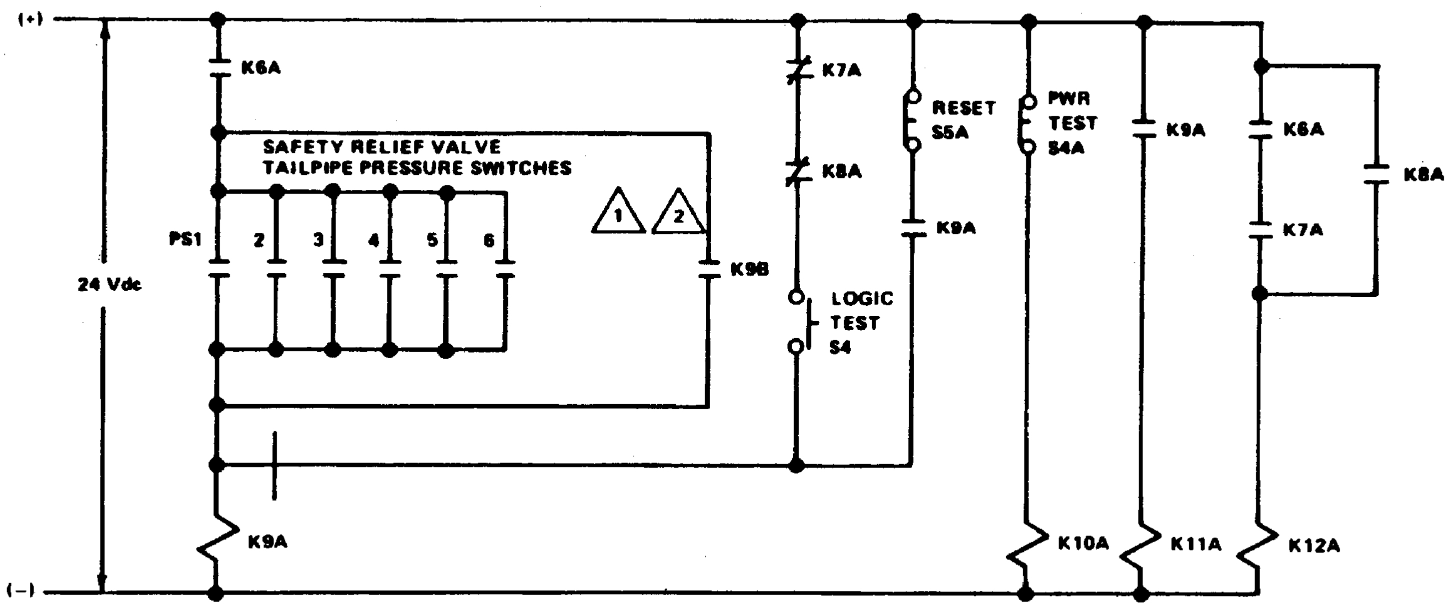
LLS RELIEF LOGIC DIAGRAM

FIGURE 7.19-1

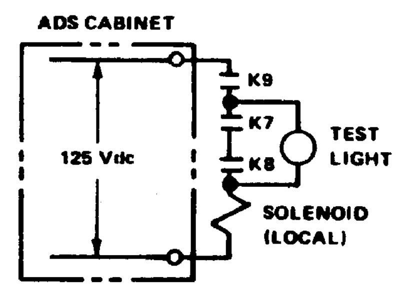


NOTES:

1 CHANNEL C HAS FIVE PRESSURE SWITCHES.

2 DIVISION II UTILIZES RELAY CONTACTS FROM THE SAFETY RELIEF VALVE MONITOR SYSTEM, SIX CONTACTS IN CHANNEL B, AND FIVE CONTACT IN CHANNEL D.

3 DEVICE NUMBERS ILLUSTRATIVE (NOT MPL NUMBERS).



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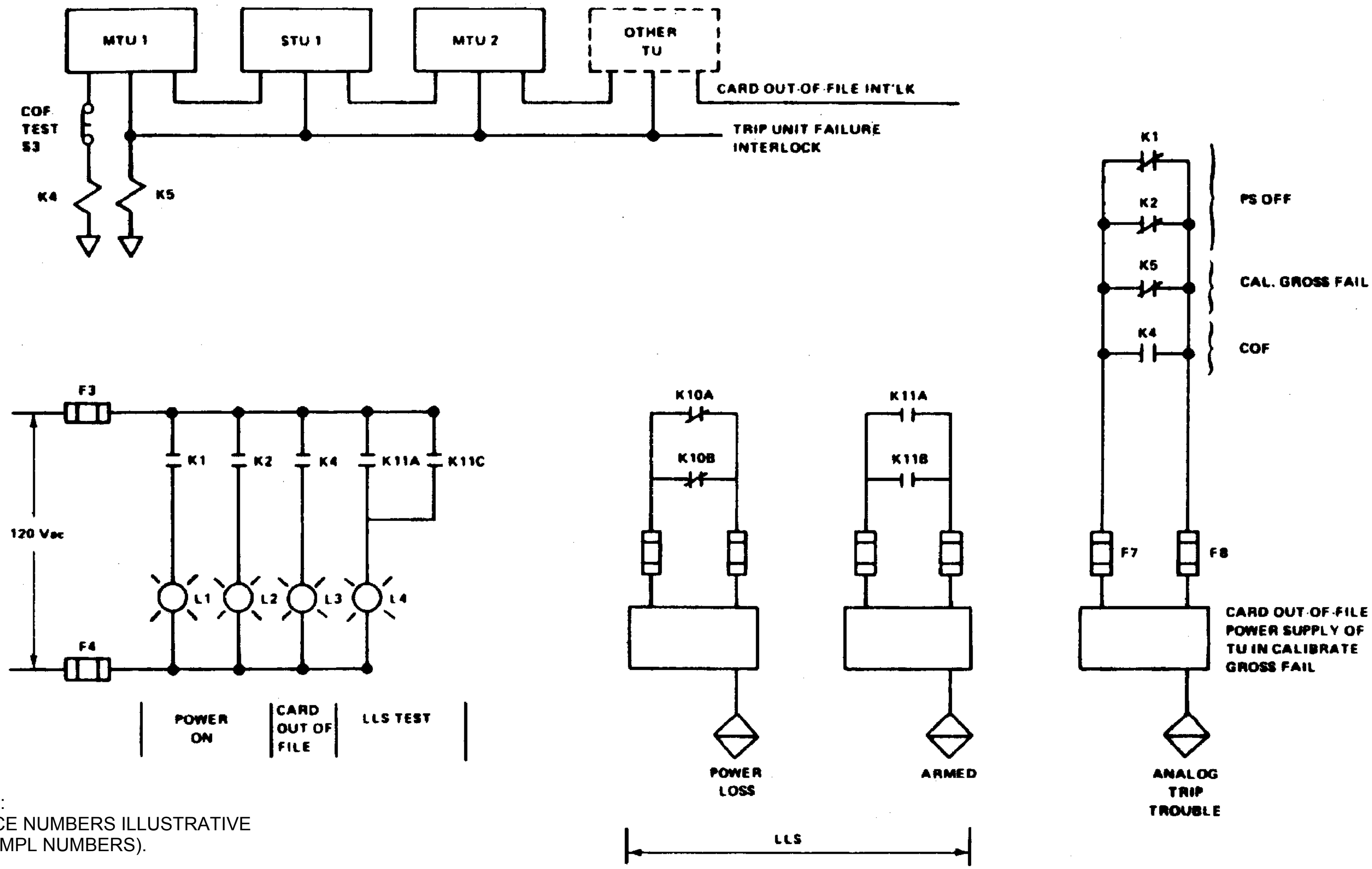
LLS LOGIC FOR CHANNEL A
(TYPICAL FOR CHANNELS B, C, AND D)

FIGURE 7.19-2



NOTE:
DEVICE NUMBERS ILLUSTRATIVE
(NOT MPL NUMBERS).

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CHANNELS A AND C INDICATORS
(TYPICAL FOR CHANNELS B AND D)

FIGURE 7.19-3

7.20 POST-ACCIDENT SAMPLING SYSTEM

See subsection 7.6.11 of the HNP-2-FSAR.

7.21 SAFETY PARAMETER DISPLAY SYSTEM/EMERGENCY RESPONSE DATA SYSTEM/NRC EMERGENCY RESPONSE DATA SYSTEM

See HNP-2-FSAR section 7.9 for a description of HNP-1 Safety Parameter Display System/Emergency Response Data System/NRC Emergency Response Data System.

7.22 ROD WORTH MINIMIZER

See HNP-2-FSAR section 7.10 for a description of HNP-1 rod worth minimizer.

7.23 ANTICIPATED TRANSIENT WITHOUT SCRAM-RECIRCULATION PUMP TRIP (ATWS-RPT)

See HNP-2-FSAR paragraph 7.6.10.7 for a description of HNP-1 ATWS-RPT.

7.24 INFORMATION SYSTEMS IMPORTANT TO SAFETY

See HNP-2-FSAR subsection 7.5.3 for a description of information systems important to safety (Regulatory Guide 1.97, Revision 2 requirements).

8.0 ELECTRICAL POWER SYSTEMS

8.1 SUMMARY DESCRIPTION

The basic function of the unit electrical power system is to supply a highly reliable source of electric power to the auxiliary systems. During normal operation, the electrical power for the unit auxiliary loads connected to 4.16-kV buses 1A, 1B, 1C, and 1D is supplied through the unit auxiliary transformers. Additionally, one of the startup transformers provides the source of normal power for 4.16-kV buses 1E, 1F, and 1G. Electric power required during startup and shutdown is drawn from the transmission system through the startup transformers. Emergency power is supplied from one of two startup transformers or from three diesel generators. The normal dc supply is from battery chargers with the batteries floating on continuous charge. The plant batteries supply emergency dc power.

8.2 TRANSMISSION SYSTEM

See HNP-2-FSAR subsections 8.2.1 and 8.2.2.

8.3 AUXILIARY ELECTRICAL POWER SYSTEM

8.3.1 SAFETY OBJECTIVE

The emergency service portion of the auxiliary power distribution system, under all anticipated operational occurrence and accident conditions, distributes ac power required to safely shut down the reactor, maintains the shutdown condition, and operates all auxiliaries necessary for plant safety.

8.3.2 SAFETY DESIGN BASES

The safety design bases of the auxiliary electrical power system are as follows:

A. The emergency service portion of the auxiliary power system distributes power to the unit auxiliaries and all loads which are essential to plant safety.

B. The auxiliary power system, normal and emergency service portions, is arranged so that a single failure does not prevent or impair the operation of essential unit safety functions.

C. The emergency service portions of the auxiliary power system are supplied from both offsite and onsite ac power sources.

D. The emergency service portion of the auxiliary power system is in accordance with the "Proposed Institute of Electrical and Electronics Engineers Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations," dated June 1969.

8.3.3 POWER GENERATION OBJECTIVE

The entire auxiliary power distribution system, normal and emergency service portions, distributes ac power to all ac auxiliaries required to start up, operate, and shut down the plant.

8.3.4 POWER GENERATION DESIGN BASIS

The auxiliary power distribution system distributes power to all auxiliaries necessary for normal plant operation.

8.3.5 DESCRIPTION

There are seven 4160-V buses (1A, 1B, 1C, 1D, 1E, 1F, and 1G) in the station auxiliary power distribution system as shown in figure 8.3-1. Buses 1A and 1B supply power to the large motors and are designated as normal buses. Buses 1C and 1D are also normal buses and supply power to other station auxiliaries requiring ac power during planned operations. The normal buses are located in the turbine building. The three emergency service buses are 1E, 1F, and 1G. These are located in the diesel building and supply power to essential loads required during normal operation, anticipated operational occurrences, and accidents.

Power is distributed to the normal 4160-V auxiliary buses during normal operation from either the unit service transformers 1A and 1B or from the startup service transformers 1C and 1D. The startup transformers are used to supply the 4160-V buses during normal startup, maintenance outage, and shutdown. After the main generator is synchronized to the 230-kV system and a minimum stable load established, each 4160-V normal bus is manually transferred from the starting source to the unit power source. The transfer is a hot transfer following synchronization checks. This type of transfer results in the momentary interconnection of the starting transformer and unit transformer through a single 4160-V auxiliary bus.

The impact of open phase conditions on the capability of the startup auxiliary transformers was evaluated. The conditions analyzed consisted of single (one of three) and double (two of three) open phase conductors on the high voltage side (230 kV) of the startup auxiliary transformers. The analysis considered open phase conditions with and without ground. Open phase detection systems for the transformers were installed in accordance with the NEI Open Phase Condition Initiative. Upon detection of an open phase condition, the system will provide operator indication of the open phase condition.

Emergency buses 1E, 1F, and 1G are normally supplied by startup transformer 1D. On failure of the normal source (transformer 1D), the three emergency buses are energized from startup transformer 1C. This is accomplished by an automatic transfer. Startup transformer 1C is used as a startup supply for Unit 1 4160-V buses 1A and 1B. Startup transformer 1C can supply the transfer loads of the emergency buses 1E, 1F, and 1G in the event of a failure of transformer 1D. The transfer loads of emergency buses 1E, 1F, and 1G consist of the 600-V load centers and any of the four plant service water (PSW) pumps that are running. The maximum transfer load is within the rating of transformer 1C. With reactor core isolation cooling (RCIC) operating and a loss of transformer 1D the maximum transfer load is also within the rating of transformer 1C. Transformer 1C is rated at 28 MVA, 65°C rise, forced oil and air (FOA) continuous.

The connected load of buses 1A and 1B is 21.8 MVA. Normally, buses 1A and 1B are supplied by transformer 1B. If there is a unit trip, buses 1A and 1B transfer to transformer 1C. The transfer must be accomplished within 10 cycles.

If transformer 1D is out of service and transformer 1C is supplying power to any of the emergency buses, the automatic fast transfer of buses 1A, 1B, 1C, and 1D is blocked.

Transformer 1D is sized based on supplying 4160-V buses 1C, 1D, 1E, 1F, and 1G simultaneously. The maximum load is within the transformer rating of 33.60 MVA continuous, 65°C rise FOA. The maximum loads that can be carried on buses 1C, 1D, 1E, 1F, and 1G are the totals of loads listed in table 8.3-1 with the following exceptions:

- Bus 1C.

  Transformer 1AB is not loaded unless one of the other station service transformers is not loaded.

- Bus 1D.

  Lighting transformer 1M is not loaded unless lighting transformer 1L loses its load; the H_2 recombiner switchgear transformer (off-gas) is not loaded unless it is not receiving power from bus 1C.

  Transformer 1AB is not loaded unless the other service transformer is not loaded.

- Bus 1F.

  Transformer 1CD is not loaded unless one of the other station service transformers is not loaded.

Maximum loadings on the startup transformers 1C and 1D are verified in the Offsite Source Voltage Study, which is updated on a frequency approximately corresponding to the refueling frequency.

In the event that both startup transformer supplies are lost, the emergency buses are connected to the emergency diesel generators.

There are four normal 600-V buses (figure 8.3-2) supplied from normal 4160-V buses 1C and 1D. One spare 4160-600-V transformer is provided. The transfer to the spare transformer is a manual transfer rather than automatic. The normal 600-V switchgear is located in the turbine building. The normal buses supply power to the 600-V auxiliaries required during planned operations.

The two emergency 600-V buses, 1C and 1D, are normally supplied from separate 4160-V buses, 1E and 1G, through their own transformers, 1C and 1D, as shown in figure 8.3-2. The 600-V buses, 1C and 1D, are designed as redundant Class 1E equipment and fulfill the single failure criterion; that is, a failure affecting one bus cannot affect its redundant counterpart and the loss of either bus does not prevent operation of the minimum required engineering safety feature loads. The breakers on each 600-V bus are electrically operated with stored energy closing mechanisms operated from redundant portions of the 125-V-dc station batteries described in subsection 8.5.3.

Under normal conditions, electrical interlocks prevent closing both main breakers on each 600-V essential bus. Electrical interlocks also prevent both supply breakers from the 1CD transformer being closed at the same time. The feeder breaker from the 4160-V bus 1F to transformer 1CD is normally open, and one of the disconnect links is open. Thus, as a minimum, a failure of one interlock concurrent with two operator errors are required to parallel feed the 1C or 1D 600-V bus (i.e., to concurrently feed a single 600-V bus from two 4160-V buses). Paralleling the two buses; i.e., to concurrently feed both 600-V essential buses from a single 4160-V bus, requires a failure of one electrical interlock and four operator errors as shown in figure 8.3-2 under normal operating conditions.

Transformer 1CD, supplied from 4160-V essential bus 1F, is provided as a spare source for either essential 600-V bus. When it is being utilized, the electrical interlocks mentioned above are operational, the feeder breakers to the out-of-service transformer are open, and at least one of the disconnect links on the 600-V side of the 1CD transformer is out. Thus, as a minimum, a failure of one interlock concurrent with two operator errors in closing the out-of-service transformer feeder breaker and the 600-V bus supply breaker are required to parallel feed an essential 600-V bus; i.e., to concurrently feed a single 600-V bus from two 4160-V buses. Paralleling the two buses; i.e., to concurrently feed both 600-V essential buses from a single 4160-V bus, would require two operator errors and failure of one electrical interlock. The normally open 600-V breakers with the electrical interlock between them are considered redundant, and physical separation and/or barriers are provided.

Motors larger than 200 hp are supplied at 4160 V. Motors 200 hp and below are supplied at 600 V, except motors 3 hp and smaller are usually supplied at 208 V.

All of the 4160-V switchgear is the metal-clad indoor type. The 4160-V buses 1A, 1B, 1C, 1D, 1E, 1F, and 1G are 350 MVA; the remaining buses are 250 MVA. All 4160-V breakers are rated at 350 MVA and are electrically-operated, three-pole, stored-energy closing mechanisms operated from the 125-V-dc station batteries described in subsection 8.5.3.

All 600-V switchgear is metal-enclosed indoor type, rated 22,000 A symmetrical. Each bus is supplied by a close-coupled, silicone fluid-filled transformer, 55°C rise, 4160-600 V, delta-delta connected, rated at 1190/1368 kVA for transformers 1A, 1B, 1C, 1D, 1AA, 1BB, 1CD, and 1AB; 850/977.5 kVA for transformers 1E, 1F, 1G, 1H, 1J, and 1K; and 850 kVA for transformers 1P and 1R. The breakers are electrically operated with stored energy closing mechanisms operated from the 125-V-dc station batteries described in subsection 8.5.3.

Motor control centers (MCCs) are National Electrical Manufacturers Association Class 1. The branch breakers are molded case, manually operated breakers. All breakers are provided with magnetic short-circuit protection on all poles. MCC motor starters have provisions for thermal overload protection on poles 1 and 3, and provisions for thermal overload alarms on pole 2. The control contact of the thermal overload protection relay is bypassed during normal plant operation for MCC motor starters feeding essential motor-operated valves (MOVs), essential motors, and other safety-related MOVs, where appropriate. Essential MOVs and motors are those used for the ECCS, containment isolation function, and 10 CFR 50.49 applications.

The buses interconnecting the station service transformers and 4160-V switchgear buses are cable-type buses. The bus enclosures are aluminum with ventilation louvers. The cable is rated 90°C total temperature and has a current carrying capacity of 125% of current load.

The four station service transformers are sized to carry the station service loads. Each is a silicone fluid-filled, triple-rated transformer, 55°C rise with a 65°C rise supplementary rating. The two unit transformers are connected delta-wye with the neutral grounded through a resistor. The two starting transformers are wye-wye connected with a delta tertiary. The high-side neutral is solidly grounded while the low-side neutral is grounded through a resistor.

Motors connected to 4160-V emergency buses are designed for low voltage starting for use with diesel generators.

Control power for the 4160-V and 600-V circuit breakers is supplied from the 125-V and the 125/250 V-dc battery systems.

Adequate emergency lighting is provided for essential areas related to plant and personnel safety.

8.3.6 SAFETY EVALUATION

Provisions to assure continued availability of ac power to the emergency service portions of the auxiliary power distribution system were made in the design. The multiplicity of offsite and onsite sources feeding these buses, the redundancy of transformers and buses within the plant, and the division of critical loads between buses yield a system that has a high degree of reliability. Also, the physical separation of buses and service components provides independence to limit or localize the consequences of electrical faults or mechanical accidents occurring at any point in the system.

8.3.7 INSPECTION AND TESTING

Inspection and testing at vendor factories and initial system tests were conducted to ensure that all components are operational within their design ratings. Periodic tests are conducted to detect the deterioration of equipment in the system toward an unacceptable condition. Tests also demonstrate the capability of equipment, which is normally deenergized, to perform properly when energized.

Three types of preoperational tests were performed on the diesel generators:

A. Test to Verify Availability of Onsite Power Sources

   The logic, including the load sequencing timers, was tested to show that in the event of an emergency the onsite power sources will be started, connected to the appropriate buses, and the emergency loads started in the proper sequence.

B. Test to Verify Load Carrying Capabilities

   Each diesel generator was paralleled to the transmission systems, loaded to rated capacity, and operated at that level to show that there is adequate capability to carry rated load continuously.

C. Prototype Test to Demonstrate Capability of Onsite Electrical Power System to Accept or Reject Emergency Loads on Loss of Coolant Accidents

A prototype test on diesel generator 1C only was performed based on loads available on bus 1G. Initially, generator 1C was loaded with the residual heat removal service water (RHRSW) pump 1B [equivalent in rating to the core spray (CS) pump]. After the initial loading, RHRSW pump 1D and PSW pump 1B were manually connected to the generator at the prescribed time intervals. A stop watch was used to measure the time intervals. One of the largest loads was rejected to demonstrate the capability of the onsite electrical power system to reject the largest load. This test simulated automatic sequential loading conditions compared to the actual loadings encountered during the first 10 s of the emergency operation.

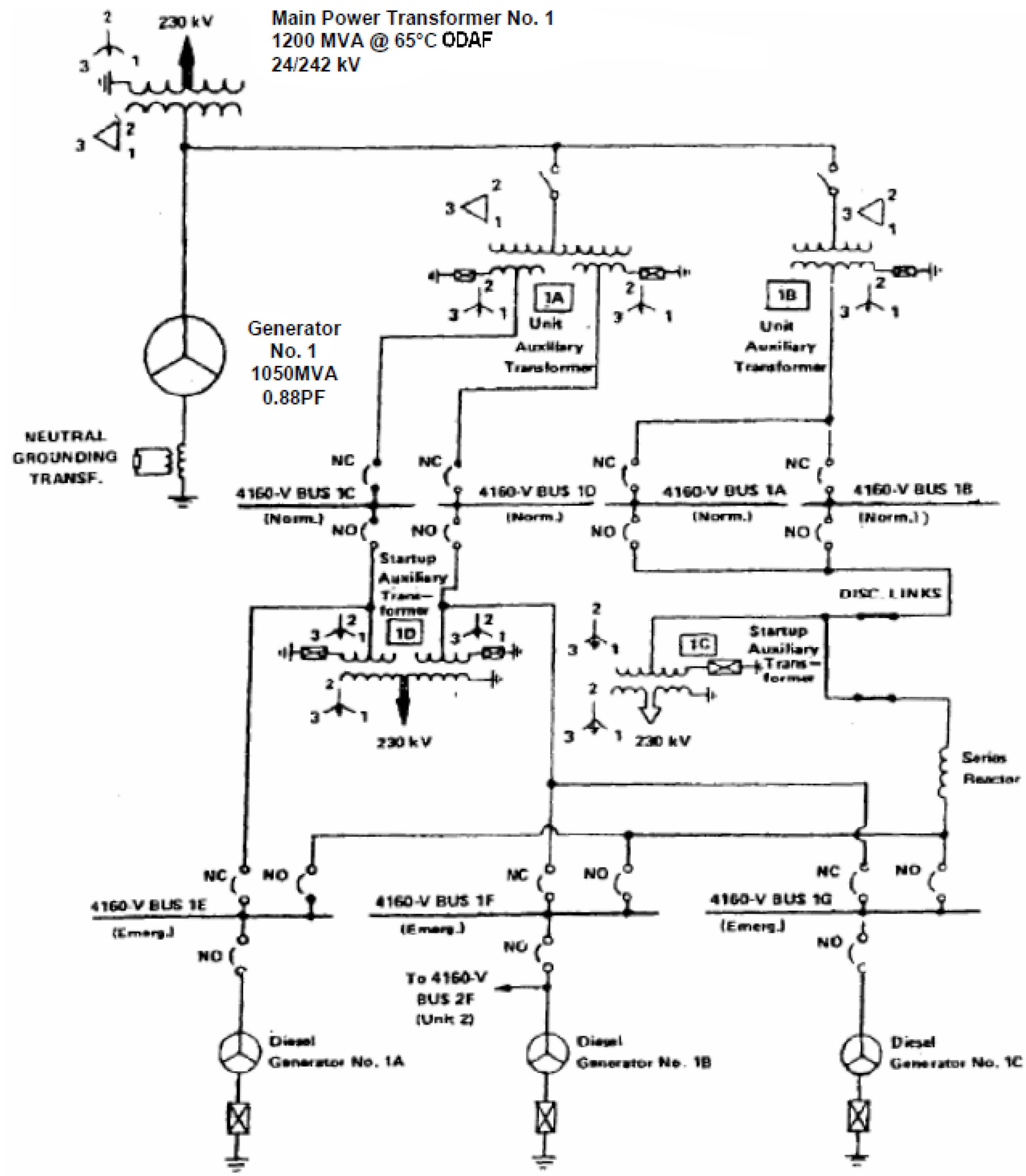
TABLE 8.3-1 (SHEET 1 OF 2)

TABULATION OF LOADS ON 4160-V SWITCHGEAR BUSES

4160-V bus 1A		
Recirculation pump 1A ASD	6665	kVA
Circulation water pump 1A	5000	hp
4160-V bus 1B		
Recirculation pump 1B ASD	6665	kVA
Circulation water pump 1B	5000	hp
4160-V bus 1C		
Condensate pump 1C	1500	hp
Condensate booster pump 1C	2250	hp
Cooling tower feeders	2800	hp
4160-600 V station service transformer 1A	1368	kVA
4160-600 V station service transformer 1AA	1368	kVA
4160-600 V station service transformer 1BB	1368	kVA
Service building 4160-277/480 V transformer 1N	750	kVA
Lighting transformer 1L	425	kVA
4160-600 V station service standby transformer 1AB	1368	kVA
H_2 recombiner (off-gas)	850	kVA
Turbine building refrigeration	554	hp
4160-V bus 1D		
Condensate pump 1A	1500	hp
Condensate pump 1B	1500	hp
Condensate booster pump 1A	2250	hp
Condensate booster pump 1B	2250	hp
Cooling tower feeders	2800	hp
4160-600 V station service transformer 1B	1368	kVA
Lighting transformer 1M	425	kVA
4160-600 V station service standby transformer 1AB	1368	kVA
H_2 recombiner (off-gas)	850	kVA
Turbine building refrigeration	554	hp
4160-600 V switchyard transformer	600	kVA
4160-V bus 1E		
CS pump 1A	1250	hp
RHRSW pump 1A	1250	hp
RHR pump 1A	1000	hp
Control rod drive (CRD) pump 1A	250	hp
Fire pump	250	hp
4160-600 V station service transformer 1C	1368	kVA
PSW pump 1A	700	hp

TABLE 8.3-1 (SHEET 2 OF 2)

4160-V bus 1F		
RHRSW pump 1C	1250	hp
RHR pump 1C	1000	hp
RHR pump 1D	1000	hp
CRD pump 1B	250	hp
4160-600 V station service transformer 1CD	1368	kVA
PSW pump 1C	700	hp
PSW pump 1D	700	hp
4160-600 V transformer (MCC 1B)	225	kVA
4160-600 V transformer (MCC 1D)	225	kVA
4160-V bus 1G		
RHRSW pump 1B	1250	hp
RHRSW pump 1D	1250	hp
RHR pump 1B	1000	hp
4160-600 V station service transformer 1D	1368	kVA
PSW pump 1B	700	hp
CS pump 1B	1250	hp



NOTE: See table 8.3-1 for tabulation of loads on 4160-V buses.

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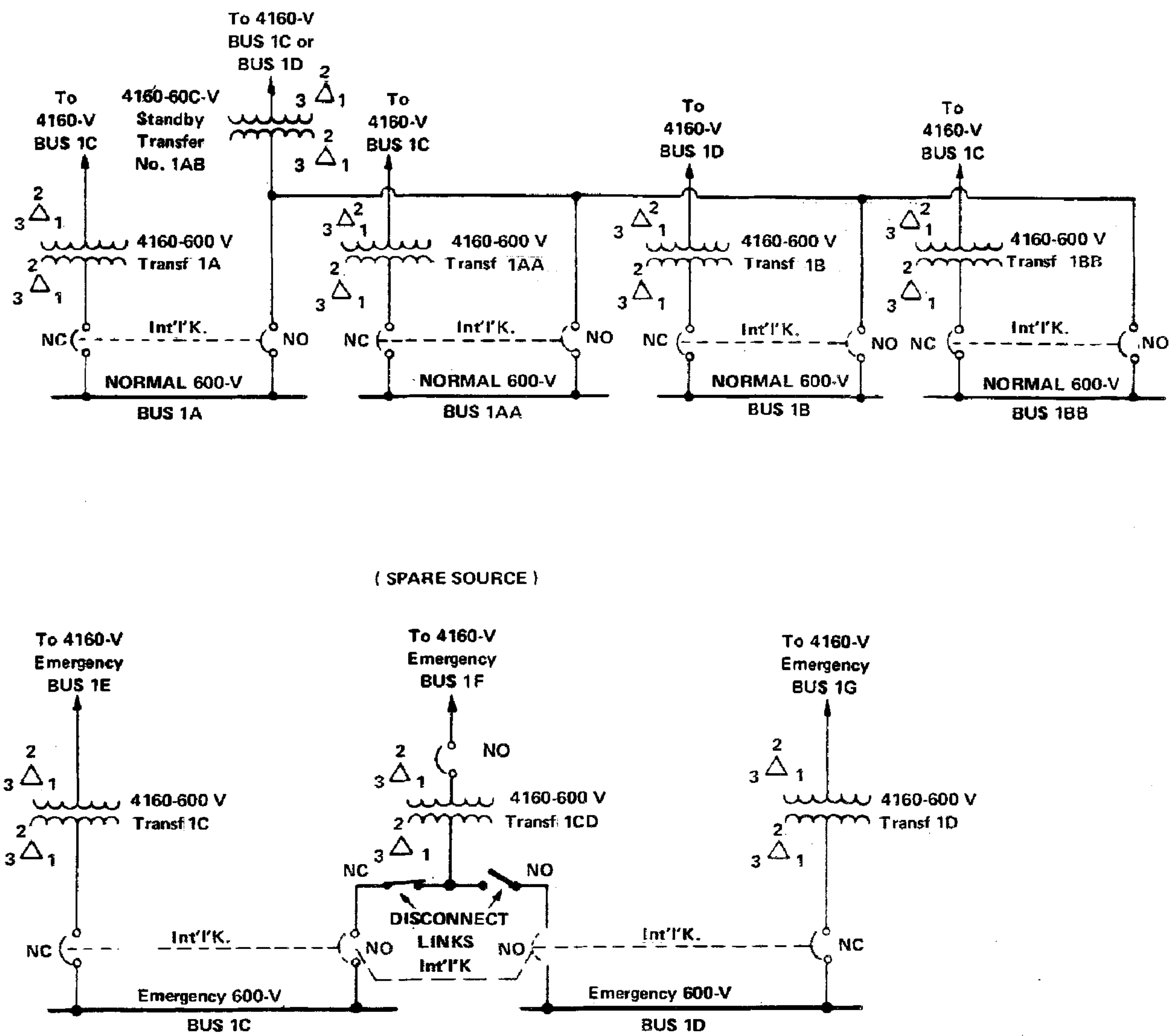

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ELECTRICAL POWER SYSTEM

FIGURE 8.3-2

8.4 STANDBY ac POWER SUPPLY

8.4.1 SAFETY OBJECTIVE

The safety objective of the standby ac power supply is to provide a reliable source of onsite electrical power for the safe shutdown of the reactors.

8.4.2 SAFETY DESIGN BASES

A. The standby ac power supply design conforms to the applicable sections of the following IEEE Standards:

a. IEEE 308-1969 “Proposed Institute of Electrical and Electronics Engineers Standard Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations”

This standard is only applicable to the LOCA/LOSP time cards associated with the Square D Masterpact Breakers in the Diesel Building.

b. IEEE 730-2002, “IEEE Standard for Software Quality Assurance Plans”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

c. IEEE 828-1990, “IEEE Standard for Software Configuration Management Plans”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

d. IEEE 829-1983, “IEEE Standard for Software Test Documentation”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

e. IEEE 830-1993, “IEEE Recommended Practice for Software Requirements Specifications”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

f. IEEE 1008-1987, “IEEE Standard for Software Unit Testing”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

g. IEEE 1012-1998, “IEEE Standard for Software Verification and Validation”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

h. IEEE 1028-1997, “IEEE Standard for Software Reviews and Audits”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

i. IEEE 7-4.3.2-2003, “Standard Criteria for Digital Components in Safety Systems of Nuclear Power Generating Stations”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators.

j. IEEE 323-1974, “Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators and the Square D Masterpact Breakers in the Diesel Building.

k. IEEE 344-1975, “Recommended Practices for Seismic Qualification of Class 1E Equipment”

This standard is only applicable to the LOCA/LOSP time cards associated with the Emergency Diesel Generators and the Square D Masterpact Breakers in the Diesel Building.

l. IEEE 336-1971, “Installation, Inspection, and Testing Requirements for Power, Instrumentation, and Control Equipment at Nuclear Facilities”

This standard is only applicable to the Square D Masterpact Breakers in the Diesel Building.

m. IEEE 649-1991, “Standard for Qualifying Class 1E Motor Control Centers for Nuclear Power Generating Stations”

This standard is only applicable to the Square D Masterpact Breakers in the Diesel Building.

B. The standby ac power supply is located on the plant site and is independent of offsite sources.

C. The diesel generator units are housed in a Seismic Class 1 structure located so that the equipment is protected against natural phenomena such as floods, tornadoes, earthquakes, winds, rains, ice, snow, and lightning.

D. The total number and rating of the standby diesel generator units were selected in accordance with the loads as shown in tables 8.4-1 and 8.4-2. The peak load as shown in table 8.4-3 for each of the emergency buses is less than the diesel generator 7-day rating (3250 kW) and within the guidelines of Regulatory Guide 1.9. Each diesel generator unit is capable of starting and accelerating the largest motor to rated speed and demand power in the required time as shown in table 8.4-4.

E. Each diesel generator is provided with a 40,000-gal-capacity main fuel storage tank, as well as a 1000-gal-capacity day tank. The 33,320-gal Technical Specifications requirement for each main tank represents a total amount of oil sufficient to operate any 2 diesels at 3250 kW for a period of 7 days. In addition, this amount provides fuel to operate the HNP-2 required diesels at a load sufficient to maintain power to the components required to be operable by the HNP-1 Technical Specifications for 7 days. Each diesel's day tank alone provides enough fuel for ~ 2 hours of full load operation. The combined onsite fuel capacity is sufficient to operate the diesels for longer than the time required to replenish the onsite supply from outside sources.

   The fuel storage supply system is designed to Seismic Class 1 criteria.

F. Each engine starts automatically upon a degraded or complete loss of voltage on its respective 4-kV bus, low water level in the reactor, or high drywell pressure.

G. Each diesel generator has its own battery for operating auxiliary motors and controls required for starting. Other auxiliaries required to ensure continuous operation are supplied from the emergency buses or control power transformers associated with the diesel generator.

H. The diesel generator sets have the ability to pick up loads in the sequence necessary for safe shutdown following design basis accidents (DBAs).

I. The diesel generators are not operated in parallel with each other at any time, whether during testing or automatic operation resulting from a loss of voltage.

J. The generators are capable of being independently synchronized for parallel operation with the startup auxiliary transformers. This synchronization is done manually for system performance tests. No two diesel generators can be synchronized to the offsite power system at the same time during testing. Each diesel generator is equipped with a key-locked mode switch that must be set in the TEST position before the generator can be synchronized and connected to the offsite power system. The mode switch key is removable in the AUTO position only.

K. The units are capable of being started or stopped manually from local control stations near the diesels or remotely from the control room.

L. The failure of any component associated with the diesel generator units does not jeopardize the capability of the remaining units to start and supply the minimum engineered safety features (ESFs).

M. Redundancy of pumps and piping does not allow the failure of one water pump or the rupture of any pipe or valve to result in the loss of more than one diesel.

N. The standby ac power supply design shall conform to the applicable sections of the following Nuclear Regulatory Commission Regulatory Guides for Power Reactors:

a. Regulatory Guide 1.152, “Criteria for Use of Computer in Safety Systems of Nuclear Power Plants,” 2010

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

b. Regulatory Guide 1.168, “Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” 2013

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

c. Regulatory Guide 1.169, “Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” 2013

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

d. Regulatory Guide 1.170, “Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” 2013

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

e. Regulatory Guide 1.171, "Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants," 2013

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

f. Regulatory Guide 1.172, "Software Requirement Specifications for Digital Computer Software and Complex Electronics Used in Safety Systems of Nuclear Power Plants," 2013

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

g. Regulatory Guide 1.100, "Seismic Qualification of Electric Equipment for Nuclear Power Plants," 1988

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

h. Regulatory Guide 1.180, "Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems," 2003

This regulatory guide is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

i. Regulatory Guide 1.75, "Physical Independence of Electric Systems," 1975

This regulatory guide is only applicable to the Square D Masterpact Breakers in the Diesel Building.

O. The standby ac power supply design shall conform to the applicable sections of the following Electric Power Research Institute Topical Reports:

a. EPRI TR-106439, "Guideline on Evaluation and Acceptance of Commercial Grade Digital Equipment for Nuclear Safety Applications," 1997

This topical report is only applicable to the LOCA/LOSP timer cards associated with the Emergency Diesel Generators.

8.4.3 DESCRIPTION

The standby ac power supply (figure 8.4-1) consists of five diesel generators for both Hatch Nuclear Plant Units 1 and 2 (HNP-1, HNP-2) and supplies standby power for 4160-V emergency service buses 1E, 1F, 1G, 2E, 2F, and 2G. Diesel generators 1A, 1C, 2A, and 2C each supply an emergency bus. Diesel generator 1B can supply either 4160-V emergency bus 1F or 2F.

Emergency buses 1E, 1F, and 1G are normally fed from startup transformer 1D with a backup feed from transformer 1C. The diesel generators cannot be paralleled with each other through the startup transformers bus supply breakers. To prevent parallel operation of the diesel generators, redundant loss of voltage signals pick up lock out relays to trip the transformer supply breakers and keep them locked out. In addition, a necessary condition for closing the diesel generator breaker is that all other supply breakers be sensed open on its bus.

Each unit consists of a diesel engine, generator, and associated auxiliaries mounted on a common base. Two completely independent air starting systems are furnished for each diesel engine either of which is capable of starting the diesel engine. Each of the air starting systems has adequate air capacity to start a single emergency diesel engine five times without recharging. Two motor-driven air compressors are available for each unit.

Each diesel generator has a separate annunciator located on the generator control panel located in the diesel building. In addition, annunciation is supplied for each diesel generator on separate annunciators in the main control room. Table 8.4-5 lists all alarms and points of annunciation for the diesel engine. Table 8.4-6 lists all alarms associated with the generator.

The lube oil system of each diesel generator consists of an engine-driven oil pump, a full-flow oil filter with internal relief valve, an oil cooler, a thermostatic three-way bypass valve, a full-flow strainer, pressure switches, high- and low-temperature alarm switches, a motor-driven circulating pump, and a motor-driven prelube pump. (See drawing nos. H-11631 and H-11638.)

When the diesel is operating, the shaft-driven pump supplies oil pressure for the system. The oil temperature is controlled by the thermostatic three-way valve regulating the amount of oil passing through the cooler.

During shutdown the motor-driven circulating pump is energized by a low-speed switch, and oil from the rear of the crankcase is pumped through an electric heater to the front of the crankcase. The heater cycles under control of temperature switches located in the strainer inlet and heater outlet piping, to provide a fairly even oil temperature at any point in the sump. This arrangement enables the engine to come up to rated speed immediately after starting.

The prelube oil pump is used to prelube the engine prior to nonemergency starts. The prelube pump is not utilized on emergency starting.

Conditions of high or low oil temperature or low oil pressure are alarmed in the main control room.

Since the lube oil systems for the diesels are completely independent of each other, the failure of the lube oil system in one diesel will not affect the other diesels.

The ventilating equipment for the diesel generator system consists of one Mk V-2 power roof ventilator for ventilating during diesel generator shutdown, two Mk V-1 power roof ventilators (each 100% capacity) for ventilating during diesel generator operation, two motor-operated louvers with fire dampers for air intake (one louver for air intake to generator room and one louver for air intake to battery room through generator room).

Control equipment consists of one thermostat for actuating the V-2 fan, one thermostat for actuating the primary V-1 fan, air flow switches for each V-1 fan for the purpose of actuating the fan on standby in event of failure of the primary fan, limit switches for louver motors to indicate full open and full closed position of louvers, a firestat for shutting off fan motors, closing louvers, and fire dampers in event of fire. (Fire dampers are equipped with electrothermal links interconnected with firestat. With fire damper Mk FD-3 closed, airflow through louver LV-6 is shut off. Flow of cooling air is reduced such that ambient temperatures in the affected diesel generator room may exceed the maximum allowable ambient operating temperature of 122°F.) (See drawing no. H-12619.)

The sequence of control is as follows:

A. On a rise in room temperature, the thermostat for the V-2 fan activates said fan starter and louver motors of the main louver. On a continued rise in temperature, the thermostat for the two V-1 fans activates the fan, starter of the primary fan. In event of failure of this primary fan, the air flow switch in this fan activates the V-1 standby fan. Both V-1 fans are interlocked with the louver motors.

   The failure of the main louver (LV-6) to open greater than 50% of the louver area, or the failure of more than two of the four louver sections to open may result in room temperature exceeding the maximum allowable ambient operating temperature of 122°F. The ramification of this failure was evaluated in HNP-2-FSAR table 9.4-10 and is shown to be acceptable.

B. On a drop in temperature, the V-1 primary fan is deactivated, the V-2 fan is deactivated in turn, and when all fans are shut down, the louver motors close the louver blades.

C. All fans and louver motors are equipped with manual overrides.

D. All circuits in the diesels are separate and independent and none are interconnected, one diesel to the other.

The CO_2 fire protection system consists of a 5-ton Cardox storage tank (centered outside the east wall of the diesel generator building), a CO_2 header (routed outside diesel building from storage tank to diesel rooms by way of the roof), five guide valves (also located in each diesel room on roof), and five firestat fire detection devices (one located in each diesel room). The CO_2 header is pressurized only by a signal from a firestat device in a diesel room.

In the event of fire, the firestat actuates the CO_2 system pressurizing the header and opening the guide valve admitting CO_2 into the room with fire.

Each diesel engine is protected by various devices listed in table 8.4-7. However, only the following signals shut down the diesel engine when the MODE SELECT[a] switch is in the AUTO position:

- Starting failure.
- Engine overspeed.
- Low lube oil pressure.
- Generator differential protective relaying.

With the MODE SELECT switch in the AUTO position all other protective devices will not trip the engine but will annunciate as indicated by table 8.4-5. Table 8.4-8 lists the generator protective devices.

Each generator is grounded through a high resistance. A ground detector circuit annunciates a ground condition in the main control room. The neutral ground-fault relays are not designed to trip the emergency diesel generators.

The fuel supply for the diesel engines consists of five 40,000-gal main fuel storage tanks. These storage tanks have 8 ft of ground cover and are separated from adjacent tanks by 8 ft. The storage tanks can supply any diesel engine. Additionally, each diesel generator is equipped with a 1000-gal-capacity day tank. Each main tank is equipped with two 100% capacity fuel oil transfer pumps which are supplied power from different division sources. Each of these redundant pumps may discharge into one of the five 1000-gal day tanks. All these outside tanks piping pumps and valves are underground. Physical separation is provided to protect against tornadoes, fires, etc. Each day tank is housed in a separate room in the diesel generator building and has a fuel capacity for ~ 2 h of full-load operations. The fuel oil transfer pumps and associated piping are redundant so that the failure of one pump or the rupture of any pipe, valve, or tank will not cause the loss of more than one diesel. In fact, only the rupture of the last isolation valve before the day tank or the breakage of the piping between the last valve and the day tank would cause even one diesel to be lost; this would occur only after the approximate 2-h supply of oil in the day tank is exhausted.

The present diesel fuel resupply consists of a minimum of three sources within a maximum distance of 125 miles from the plant site. The total normal storage of these three sources is more than 4,500,000 gal. The maximum delivery time is 24 h, and the minimum delivery time is 4 h.

The diesel generators are housed in a reinforced concrete, Class 1 seismic structure which provides protection against natural phenomena such as horizontal tornado missiles, tornadoes, floods, lightning, rain, ice, or snow.

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a. The MODE SELECT switch is a key-locked switch located in the main control room. It has two positions: TEST for testing the diesel and AUTO for all other conditions.

Each unit is completely enclosed in its own concrete cell and is isolated from other units. The walls separating the diesel generators are 18-in. reinforced concrete structural walls. Automatic fire detection and extinguishing systems are provided. A potential missile, the crankcase door, could be generated from a postulated crankcase explosion. This missile would be contained by the reinforced concrete wall.

The firestat signals the fan motors in both the generator room and the battery room to deactivate and signals the two louvers and fire dampers in the generator room exterior wall and the fire damper in the battery room interior wall to close. Each diesel room is equipped with fire doors which remain closed at all times.

Each louver is equipped with a mechanical spring that automatically closes the louver upon the loss of power to the drive mechanism.

In series with each louver is a fire damper that is held open by a fusible link. In the event of a fire, the firestat initiates an electrical charge that melts the fusible link and closes the damper. If control power is lost, the fusible link melts at 160°F and closes the damper.

The louver and damper combination ensures that the effected diesel room is closed off and retains the charge of CO_2 so that neither the fire nor the CO_2 affects the other two diesels.

Air to the diesels flows through the diesel generator external doors to the generator room louvers. The CO_2 from a postulated tank rupture would have to travel 60 ft to the end of the building, take a 90° turn, and travel another 80 ft to reach the doors. Intake louvers are located 12 ft above the floor. Thus, a rupture of the Cardox tank would not cause oxygen starvation of the diesels due to physical separation of the tank and diesel generator doors.

Upon demand, the standby diesel generators start automatically and reach rated frequency and voltage within 12 s (unloaded). Automatic starting of the diesel generator units supplying HNP-1 is initiated by a degraded or complete loss of voltage at emergency bus 1E, 1F, or 1G, or on receipt of either a reactor low water level signal or high drywell pressure signal. Loss of voltage includes, but is not necessarily limited to:

- A voltage dip to 67.3% of nominal voltage for 6.5 s or more on the emergency buses.

- A failure in any of the redundant instrument trains sensing voltage; but a coincident loss of voltage signals is required before connection of the generator to its bus is possible.

All power supply feeder and motor circuit breakers connected to each of the 4160-V emergency buses 1E, 1F, and 1G are tripped by auxiliary relays operated by redundant loss of voltage signals. This action isolates all emergency buses from the plant and each other.

Voltage relays and frequency relays detecting simultaneous conditions of normal diesel generator voltage, proper diesel generator voltage frequency, zero emergency bus voltage, and tripping of the supply breakers to the startup transformers initiate the closing of the diesel generator breaker to energize its bus.

Two sets of individual timing devices per bus are provided to sequentially start the motors for each load. The ESF loads are applied automatically in sequence at ~ 10 s intervals to minimize the initial voltage drop due to starting the induction motor-driven pumps. This method of starting motors provides flexibility in timing adjustment and independence of control. The tabulations shown in tables 8.4-1, 8.4-2, 8.4-3, and 8.4-4 assume three diesel generators are available.

The 4160-V loads and nonessential 600-V loads are tripped but the feeder breakers to the 4160/600-V station service transformers supplying the emergency 600-V load centers and their associated motor control centers remain closed. This will assure power continuity to vital auxiliaries, such as the generator seal oil pumps and instrumentation transformers, even when a reactor system problem does not accompany loss of normal power.

When the timing sequencer receives a signal of reactor vessel low water level or high drywell pressure from the reactor protection system, it starts the motors for the ESFs in the sequence shown in table 8.4-4.

At time t-plus-30 s of the DBA with all 3 emergency buses available, 4 residual heat removal (RHR) pumps and 2 core spray (CS) pumps would be in operation. Full-flow injection or spray may still be prohibited by flow or pressure sensing ESF interlocks. Failure of any one diesel or diesel battery and its buses cannot prevent attainment of minimum requirements regardless of which bus fails. The plant operator could manually drop off any excess pumping capacity at any time thereafter, but prior to proceeding into the second phase of accident control. This occurs at approximately time t-plus-19 min when reactor water level is stabilized and containment cooling begins.

The automatic starting and load sequencing times in the current design are more restrictive than the timing assumptions made in the ECCS-LOCA analyses. The RHR/LPCI and CS injection valves will pass full flow when one-half open. For design full-open valve stroke times of 63 s and 20s, respectively, this corresponds to full-flow at 32s and 10s valve stroke times, respectively.

A plant operator makes decisions based on in-place operating procedures that indicate which emergency loads may be manually connected or disconnected following a DBA after a time of 10 min. The operating procedures were developed on the basis of information contained in figure 8.4-2, and tables 8.4-1 and 8.4-9 through 8.4-15.

Loads shown in table 8.4-3 are based on the performance characteristics of the pumps. A prototype head-capacity curve was obtained for each major pump. If this information was not available, the horsepower was obtained from the maximum load on the pumps for the accident condition being evaluated.

Approximately 11 min after the DBA, the RHR system can be manually changed to a containment spray mode with containment heat being rejected to the RHR heat exchangers.

Long-term cooling equipment is started manually and placed in operation. Loading the diesel generators during this phase is under the control of the operator. To aid the operator in loading these units, instruments that continually indicate unit loads are provided. The generating capacities required for the ESF loads on 4160-V buses 1E, 1F, and 1G are shown in tables 8.4-1 and 8.4-2.

The Diesel Generators are not specifically protected from the effects of a fire in the Main Control Room. In the event of a Main Control Room evacuation because of a fire, credit is taken for local operator action to prepare the Diesel Generators for operation within 15 minutes of a LOSP event, this includes protecting the local ammeter and voltmeter indication, speed control, voltage control, and control power. This is a time critical operator action as defined in Unit 2 FSAR subsection 15.1.5.

The following is a list of long-term cooling equipment requiring manual starting, together with the information available to the plant operator relative to the operation of the equipment:

A. Residual Heat Removal Service Water (RHRSW) Pump

   The requirement for starting this pump is signaled to the main control room by suppression pool water high-temperature alarm, though the plant operator anticipates the requirement for starting this pump when the transfer is made from low pressure coolant injection to the containment spray mode of the RHR system. The full procedure for this transfer is described in chapter 4.

B. Fuel Pool Cooling and Demineralization System

   Temperature sensors alarm in the main control room when conditions in the fuel pool exceed preset parameters. The RHR pumps and heat exchangers can be put in operation to reduce the pool temperature.

8.4.4 SAFETY EVALUATION

The diesel generators are selected on the basis of their proven reliability and independence as standby power supplies. By providing redundancy in the auxiliary pumps and in the air starting system components, and by properly selecting the generator and excitation characteristics, the reliability of the diesel generator units has been further improved.

The diesel generator units required for safe shutdown of both units are capable of operating continuously at full load without any offsite supplies for a period of 7 days. Fuel for 7 days' operation is stored in underground tanks and in the day tanks. The starting air supply is stored in receivers and maintained at proper pressure. Diesel building batteries are used to furnish electrical control power to the air start system. The units and all necessary auxiliary systems are housed in Class 1 seismic structures and are protected against other natural phenomena such as tornadoes, floods, lightning, rain, ice, and snow.

The diesel generator vendor performed a dynamic analysis on the diesel generators using a modal analysis with lumped-mass modeling using the response-spectrum technique and the floor-response spectrum developed for the diesel generator building foundation. Appropriate damping factors from chapter 12 were used. These calculations were audited.

The horizontal and vertical forces were added simultaneously to the normal loads in a way to create the most critical loadings. Overturning moments, shear and tensile stresses on anchor bolts, and stresses in support brackets and weldments were checked for these loadings.

The diesel generator as a whole, including component parts, is shown to continue to function during the seismic events with stresses below allowable.

The diesel generator vendor performed seismic qualification on safety-related interlocks. This covered from overspeed and low lube oil pressure sensors through the engine governor to the engine shutdown mechanism. All safety-related electrical interlocks were analyzed as part of the control panel package.

Seismic verification of the diesel generators associated with replacement or modification activities will be consistent with the methodology developed by the Seismic Qualification Utility Group (SQUG) which utilizes earthquake experience and generic test data to verify the seismic adequacy of all classes of mechanical and electrical equipment. This methodology is documented in the Generic Implementation Procedure (GIP) which was evaluated and approved by the NRC, as documented in Supplement 2 to the Safety Evaluation Report associated with the GIP.

The normal offsite power sources are extremely reliable and the probability of failure of all offsite power is low. Probability of failure of one diesel generator with simultaneous loss-of-offsite power (LOSP) is even lower. However, with one diesel out of service, the remaining diesel generator units are capable of furnishing power for safe shutdown of both reactors, assuming the DBA has occurred in one reactor. The critical engineered safeguard loads are so divided among the three 4160-V emergency buses for each reactor that the failure of one diesel generator or diesel battery and its buses would not prevent a safe shutdown of the two reactors. Each diesel generator and its associated system are separated so that failure of any one component does not affect the operation of more than one diesel generator system.

The capability of the diesel generator to start and attain rated voltage and frequency within 12 s and to accept the engineered safeguards loads meets the necessary requirements for the standby power system.

8.4.5 INSPECTION AND TESTING

A test of the diesel generators is conducted to check for equipment failures and deterioration. Testing is conducted at equilibrium operating conditions to demonstrate proper operation at these conditions. Each diesel is manually started, synchronized to the bus, and load picked up. The diesels are loaded to at least one-fourth rated load to prevent fouling of the engines. In addition, during the test when the generator is synchronized to the bus, it is also synchronized to the offsite power source and thus is not completely independent of this source. A test is performed at least monthly to verify optimum performance.

The fuel oil transfer pumps are tested in accordance with the Technical Specifications to ensure operability requirements are met and are tested in accordance with the Inservice Testing Program to monitor for component degradation.

The test of the emergency generators during the refueling outage is more comprehensive in that it will functionally test the system; i.e., it checks diesel starting, closure of the diesel breaker, and sequencing of loads on the diesel. The diesels are started by simulation of a loss-of-coolant accident (LOCA). In addition, an undervoltage condition is imposed to simulate an LOSP. The timing sequence is checked to assure proper loading in the required time. The inspections will detect any signs of wear long before failure.

The critical emergency diesel generator protective trip functions (i.e., engine overspeed, generator differential current, and low lube oil pressure) are tested periodically per station procedures. The critical protective trip functions are tested by inputting or simulating appropriate signals and demonstrating that the associated instrumentation logic will function to actuate a trip of the emergency diesel generator.

Components of the diesel generator building heating and ventilation system are tested periodically to ensure proper operation.

TABLE 8.4-1

STANDBY DIESEL GENERATOR SYSTEM EMERGENCY LOADS[a]

Loads	Total No. of Motors	Motor Rating (hp)	Eff.	0-10 min: Minimum Required	0-10 min: Minimum (kW)	0-10 min: No. of Pumps Running	0-10 min: Demand (hp/kW)[d]	10-60 min: No. of Pumps Running	10-60 min: Demand (hp/kW)[d]	60 min and Beyond: No. of Pumps Running	60 min and Beyond: Demand (hp/kW)[d]
HNP-1 Design Basis Accident											
CS pumps	2	1250	94	1	1012	2	2550/2024	1	1275/1012	1	1275/1012
RHR pumps	4	1000	93	2	1805	4	4500/3610	1	1125/ 902	1	1125/ 902
RHRSW pumps	4	1250	93.5	0	0	0	0	2	2400/1915	2	2400/1915
Plant service water (PSW) pumps	4	700	93	1	481	3	1800/1444	2	1200/ 963	2	1200/ 963
600-V loads[c]	-	-		-	≤ 1616[e]	-	≤ 1616[e]	-	≤ 2140[e]	-	≤ 2140[e]
Subtotal demand (kW)					≤ 4914[e]		≤ 8694[e]		≤ 6932[e]		≤ 6932[e]
HNP-2 Emergency Shutdown											
PSW pumps	4	700				2	1412	2	1412	2	1412
RHR Pumps	4	1000				0	0	1	1125	1	1125
RHRSW pumps	4	1250				0	0	2	2390	2	2390
Control rod drive water pumps	2	250				0	0	0	0	1	260
Emergency ac lighting	-	90[b]				-	120	-	120	-	120
Other 600-V loads[c]							1719		3323		1634
Subtotal demand (hp)							3251		6651		6941
Subtotal demand (kW)							2697		5518		5759
Total demand (kW)							≤ 11,363		(a)		(a)

a. The DBA will initiate the starting of both CS pumps and all four RHR pumps. The 0-10 min loading of the accident unit is based on the operation of all three emergency buses or diesel generator units. The loading beyond 10 min is based on the operator manually switching loads in accordance with minimum process system requirements. The Minimum Required column of this table demonstrates that four of five 2850-kW diesel generator units are adequate to supply the ESFs loads of one unit concurrent with the emergency shutdown loads of the other. For the time beyond 10 min, the minimum required number of pumps is shown in tables 8.4-9 through 8.4-15.
b. In kW.
c. See table 8.4-2.
d. The hp/kW loads considered are for a maximum hp/kW load on the pumps, except for PSW pumps where the load is considered with the turbine building isolated.
e. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-2

LOADS ON 600-V ESSENTIAL BUSES

Loads	Total No. of Motors	Motor Rating
Drywell cooling units	3	20 hp
Drywell cooling units	4	60 hp
Drywell cooling units	5	25 hp
Control room air-conditioning compressors	3	50 hp
Control room air-conditioning fans	3	15 hp
CS and RHR pump room cooling units	4	15 hp
Reactor core isolation cooling pump room cooling units	2	3 hp
High-pressure coolant injection pump room cooling units	2	3 hp
Intake structure essential loads	-	46 hp
SGTS exhaust fans	2	15 hp
Standby liquid control tank startup heaters	1	35 kW
Standby gas filter heaters	2	15 kW
Standby liquid control tank heaters	1	10 kW
Main stack power supply	-	30 kW
Generator room fans	6	5 hp
Generator water jacket heaters	3	15 kW
Generator lube oil heaters	3	15 kW
Generator room heaters	9	12.5 kW
Switchgear room heaters	9	7.5 kW
208-V essential small fan and pump motors	-	30 hp
Battery charger	2	30.64 kW
PSW pump for diesel-B	1	60 hp
Control room duct heaters	1	60 kW
LPCI inverter room coolers[a]	2	15 hp
Reactor building floor drain sump pump	4	7.5 hp
Computer room A/C unit	1	6 hp
CO_2 storage room A/C unit	1	6 hp

a. HNP-1 and HNP-2 LPCI inverters were replaced with Class 1E power supplies backed by dedicated diesel generators (HNP-1-FSAR figure 8.5-1, HNP-2-FSAR figure 8.3-8).

TABLE 8.4-3

LOAD DISTRIBUTION ON EMERGENCY BUSES DURING A LOCA 0 TO 10 MIN AFTER DBA

Engineered Safety Features	Load Distribution						Minimum Required
	Bus 1E		Bus 1F		Bus 1G		
	No.	kW	No.	kW	No.	kW	
CS pump	1A	1011.9			1B	1011.9	1
RHR pumps	1A	902.4	1C 1D	902.4 902.4	1B	902.4	2
PSW pumps	1A	481.3	1C or 1D	481.3	1B	481.3	1
Emergency 600-V loads		≤ 664.5[a][c]		≤ 249.8[c]		≤ 701.3[b][c]	1/2
Total kW		≤ 3060.1[c]		≤ 2535.9[c]		≤ 3096.9[c]	

a. Includes 15.2-hp-MOV load.
b. Includes 13.6-hp-MOV load.
c. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-4

SEQUENCE FOR AUTOMATICALLY CONNECTING EMERGENCY ac LOADS ON LOCA[a][c]

Event	Time (s)	Action/Comments
Low reactor water level or high drywell pressure.	0	Signal standby ac power supply to start.
		Power available to RHR/LPCI Injection and RRS Discharge motor-operated valves.[d]
Standby ac system ready for loading.	12	Apply power to 600-V emergency load centers and motor-operated isolation valves.
		Start SGTS.
		Energize emergency lighting.
		Power available to CS injection valves.
		Start both CS pumps.
		Start one RHR pump.
Reactor depressurizes, allowing pressure permissive logic for LOCA valves to be satisfied.[c] One RHR pump and both CS pumps operating.	22	RHR and CS injection valves begin to open.
		Start 3 RHR pumps.
	23	Recirculation loop discharge valves begin to close.
All RHR pumps operating.	30	Start two PSW pumps.[b]
CS injection valves open sufficiently for full CS flow.[e]	32	Based on design value 20-s full-open CS injection valve stroke time.[f]
RHR injection valve open sufficiently for full LPCI flow.[e]	53	Based on design value 63-s RHR injection valve full-open stroke time.[f]
Recirculation line discharge valve fully closed.	64	Based on design value 41-s recirc discharge valve stroke time.[f]

a. The sequence for automatic connection of ac loads is based on operation of all three emergency buses and diesel generator units.
b. PSW pumps are tripped on loss of voltage but not on LOCA alone.
c. Times are supported by the ECCS-LOCA analyses described in subsection 6.3.3 of HNP-2-FSAR.
d. Power supplied from unaffected unit's 600-V emergency load centers.
e. Full flow achieved at 50% of full-open stroke time.
f. Design value valve stroke times are supported by the ECCS-LOCA analyses.

TABLE 8.4-5

DIESEL ENGINE ALARMS

Alarm Condition	Sensor	Annunciated	
		Diesel Building	Main Control Room
Lube oil temperature low	Temperature switch	Yes	Yes
Lube oil temperature high	Temperature switch	Yes	Yes
Jacket coolant temp low	Temperature switch	Yes	Yes
Jacket coolant temp high	Temperature switch	Yes	Yes
Lube oil pressure low[a]	Pressure switch	Yes	Yes
Fuel oil pressure low[a]	Pressure switch	Yes	Yes
Raw water pressure low[a]	Pressure switch	Yes	Yes
Jacket coolant pressure low[a]	Pressure switch	Yes	Yes
Start failure	Time delay	Yes	Yes
Engine overspeed	Speed switch	Yes	Yes
High crankcase pressure[b]	Pressure switch	Yes	Yes
Control at engine	Mode switch	Yes	Yes
Day tank fuel oil level low	Level switch	Yes	Yes
Day tank fuel oil level high	Level switch	Yes	Yes
Exp tank jacket cool level low	Level switch	Yes	Yes
No. 1 air reserve low	Pressure switch	Yes	Yes
No. 2 air reserve pressure low	Pressure switch	Yes	Yes
Emergency engine	LO relay	No	Yes

a. These four alarms are qualified by time delay to allow pressure buildup after starting.
b. Time delay on start.

TABLE 8.4-6

GENERATOR ALARMS

Alarm Condition	Sensor	Annunciated: Diesel Building	Annunciated: Main Control Room
Generator winding temperature high	Temperature monitor	No	Yes
Generator bearings temperature high	Temperature monitor	No	Yes
Generator neutral overcurrent	IAC relay	No	Yes
Generator differential operation[a]	CFDs and HEA	No	Yes
Generator overcurrent, voltage restored[a]	IJCVs relay	No	Yes
Generator overvoltage[b]	IAV relay	No	Yes
Generator loss of excitation[b]	CEH relay	No	Yes
Generator reverse power	ICW relay	No	Yes
Generator field ground	DGF relay	No	Yes

a. Relay target in diesel building.
b. Functions only in TEST mode.

TABLE 8.4-7

DIESEL ENGINE PROTECTION

Abnormal Condition	Protective Device	Protective Function Versus Mode Select Switch Position	
		NORMAL	TEST
Starting failure	TD relay	Yes	Yes
Engine overspeed	Speed switch	Yes	Yes
Lube oil temperature high	Temperature switch	No	Yes
Jacket coolant temperature high	Temperature switch	No	Yes
Lube oil pressure low[a]	Pressure switch	Yes	Yes
Jacket coolant pressure low[a]	Pressure switch	No	Yes
Crankcase pressure high[b]	Pressure switch	No	Yes

a. TD on start to allow pressure buildup.
b. TD on start.

TABLE 8.4-8

DIESEL GENERATOR PROTECTION

Abnormal Condition	Protective Device		Protective Function Versus Mode Select Switch Position AUTO	TEST
Generator differential[a]	CFD	HEA	Yes	Yes
Generator overcurrent, volt reactor[b]	IJCV	ACB	Yes	Yes
Generator loss of excitation[a]	CEH	HEA	No	Yes
Generator reverse power[a]	ICW	HEA	No	Yes

a. Trips LO relay and voltage regulator.
b. Trips generator ACB only.

TABLE 8.4-9

LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA AND LOSP[a] 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution						Minimum Required
	Bus 1E		Bus 1F		Bus 1G		
	No.	kW	No.	kW	No.	kW	
CS pump	1A	1011.9					1
RHR pumps			1C	902.4	1B	902.4	1
RHRSW pumps	1A	957.4	1C	957.4			2
PSW pumps			1C	481.3	1B	481.3	1
Emergency 600-V loads		≤ 905.7[b]		≤ 212.3[b]		≤ 1022.0[b]	1/2
Total kW		≤ 2875.0[b]		≤ 2553.4[b]		≤ 2405.7[b]	

a. Under these circumstances, if there is a loss of voltage on bus 1G, no operator action is required. In case of loss of voltage on bus 1F, the operator will restore supply to RHRSW pump 1B and PSW pump 1A, and may restrict the use of some 600-V loads based on available emergency diesel generator (EDG) capacity. In case of loss of voltage on bus 1E, see table 8.4-10.

b. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-10

LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA, LOSP, AND LOSS OF VOLTAGE ON BUS 1E 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution						Minimum Required
	Bus 1E		Bus 1F		Bus 1G		
	No.	kW	No.	kW	No.	kW	
CS pump					1B	1011.9	1
RHR pumps			1C	902.4			1
RHRSW pumps			1C	957.4	1B	957.4	2
PSW pumps			1C	481.3			1
Emergency 600-V loads				≤ 439.0[a]		≤ 1022.0[a]	1/2
Total kW				≤ 2780.1[a]		≤ 2991.3[a]	

a. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-11

LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA AND LOSP[a] 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution						Minimum Required
	Bus 1E		Bus 1F		Bus 1G		
	No.	kW	No.	kW	No.	kW	
CS pump					1B	1011.9	1
RHR pumps	1A	902.4	1D	902.4			1
RHRSW pumps			1C	957.4	1B	957.4	2
PSW pumps	1A	481.3	1D	481.3			1
Emergency 600-V loads		≤ 905.7[b]		≤ 212.3[b]		≤ 1022.0[b]	1/2
Total kW		≤ 2289.4[b]		≤ 2553.4[b]		≤ 2991.3[b]	

a. Under these circumstances, if there is a loss of voltage on bus 1E, some operator actions are required. In case of a loss of voltage on bus 1G, see table 8.4-12. If there is a loss of voltage on bus 1F, the operator will restore supply to RHRSW pump 1A and PSW pump 1B, and may restrict the use of some 600-V loads based on available EDG capacity.

b. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-12

**LOAD DISTRIBUTION ON EMERGENCY BUSES
POST-LOCA, LOSP, AND LOSS OF VOLTAGE ON BUS 1G
10 TO 60 min AFTER DBA**

Engineered Safety Features	Load Distribution						Minimum Required
	Bus 1E		Bus 1F		Bus 1G		
	No.	kW	No.	kW	No.	kW	
CS pump	1A	1011.9					1
RHR pumps			1C	902.4			1
RHRSW pumps	1A	957.4	1C	957.4			2
PSW pumps			1C	481.3			1
Emergency 600-V loads		≤ 905.7[a]		≤ 212.3[a]			1/2
Total kW		≤ 2875.0[a]		≤ 2553.4[a]			

a. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-13

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA, LOSP, AND LOSS OF DIESEL GENERATOR BATTERY 1A[a] 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution: Bus 1F No.	Bus 1F kW	Bus 1G No.	Bus 1G kW	Minimum Required
CS pump			1B	1011.9	1
RHR pumps	1D	902.4			1
RHRSW pumps	1C	957.4	1B or 1D	957.4	2
PSW pumps	1D	481.3			1
Emergency 600-V loads		≤ 439.0[b]		≤ 1022.0[b]	1/2
Total kW		≤ 2780.1[b]		≤ 2991.3[b]	

a. The loading configuration corresponds to the loads required to cope with the worst-case break in the Division II recirculation discharge loop. The worst-case load on bus 1F is ≤ 2979.7 kW, and on bus 1G, the worst-case load is ≤ 2936.8 kW to cope with a break in the Division II CS discharge loop. Some operator actions are required to add 600-V loads on bus 1F.

b. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

TABLE 8.4-14

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA, LOSP, AND LOSS OF DIESEL GENERATOR BATTERY 1C[(a)] 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution				Minimum Required
	Bus 1E		Bus 1F		
	No.	kW	No.	kW	
RHR pumps	1A	902.4	1D	902.4	2
RHRSW pumps	1A	957.4	1C	957.4	2
PSW pumps			1C and 1D	481.3 481.3	2
Emergency 600-V loads		≤ 905.7[(b)]		≤ 212.3[(b)]	1/2
Total kW		≤ 2765.5[(b)]		≤ 3034.7[(b)]	

a. The loading configuration corresponds to the loads required to cope with the worst-case break in the Division I CS loop. The worst-case load on bus 1E is ≤ 2875.0 kW, and on bus 1F, the worst-case load is ≤ 2552.1 kW to cope with a break in the Division I recirculation discharge loop. Some long-term operator actions are required for loads on bus 1F.

b. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.

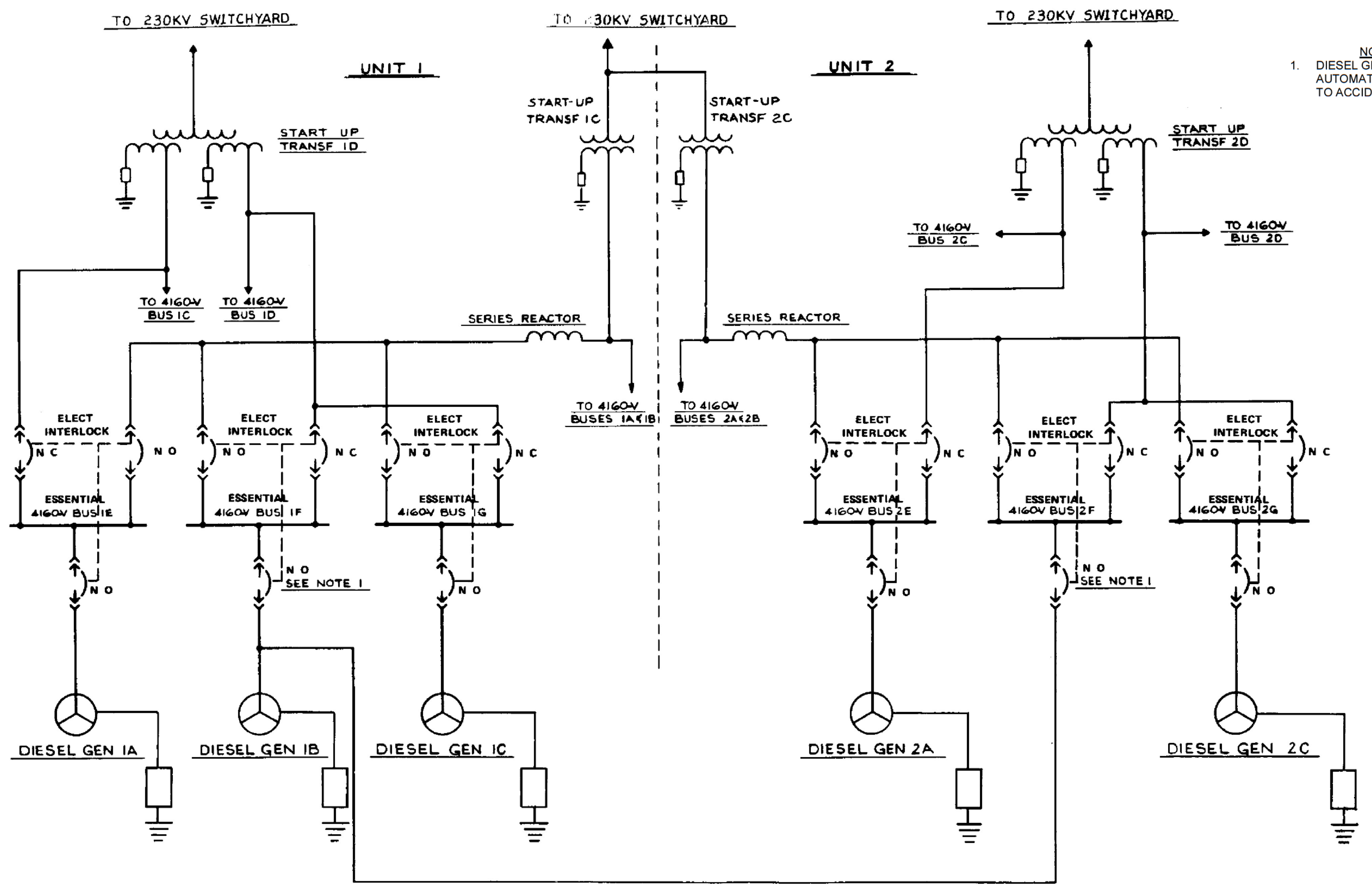
TABLE 8.4-15

POSSIBLE LOAD DISTRIBUTION ON EMERGENCY BUSES POST-LOCA, LOSP, AND LOSS OF DIESEL GENERATOR BATTERY 1B[a] 10 TO 60 min AFTER DBA

Engineered Safety Features	Load Distribution				Minimum Required
	Bus 1E		Bus 1G		
	No.	kW	No.	kW	
CS pump	1A	1011.9			1
RHR pumps			1B	902.4	1
RHRSW pumps	1A	957.4	1B	957.4	2
PSW pumps	1A	481.3	1B	481.3	2
Emergency 600-V loads		≤ 741.0[b]		≤ 740.0[b]	1/2
Total kW		≤ 3191.6[b]		≤ 3081.1[b]	

a. The loading configuration corresponds to the loads required to cope with the worst-case break in recirculation loop A or the worst-case break in CS loop B. The worst-case load on bus 1E is ≤ 3191.6 kW, and on bus 1G, the worst-case load is ≤ 3081.1 kW to cope with a break in recirculation loop B or CS loop A. Some operator actions are required to shed 600-V loads on buses 1E and 1G.

b. The values shown are acceptable analyzed values supported by calculations. The present actual loads are less than or equal to these values.



NOTES

1. DIESEL GENERATOR 1B IS AUTOMATICALLY ALIGNED TO ACCIDENT UNIT.

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REF DWG H-23350 REV 5
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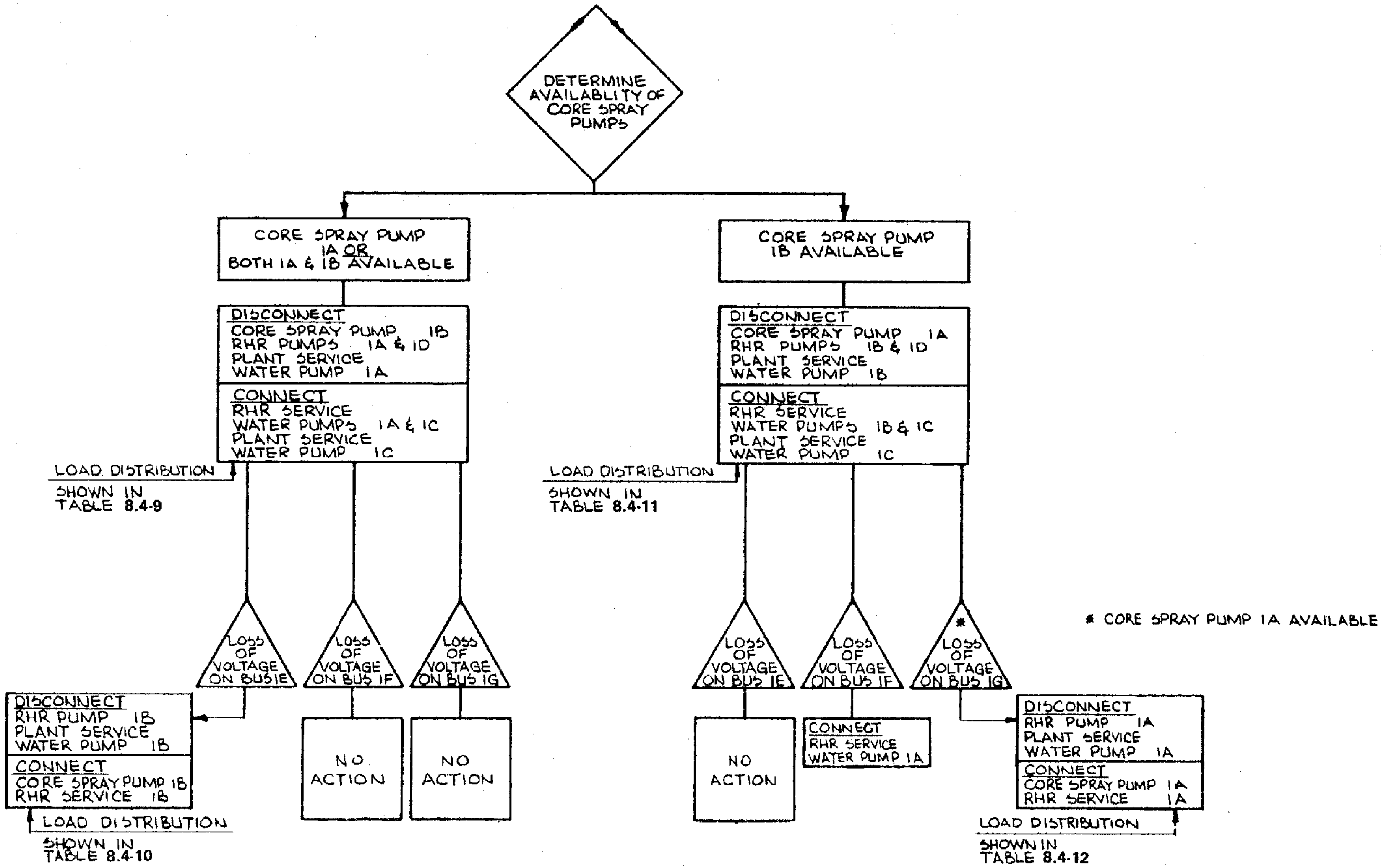
4160-V STANDBY ac POWER SUPPLY

FIGURE 8.4-1



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LOGIC FOR MANUAL LOADING OF DIESEL GENERATORS

FIGURE 8.4-2

8.5 125-V AND 125/250-V-dc POWER SYSTEMS

8.5.1 SAFETY OBJECTIVE

The safety objective of the 125-V and 125/250-V-dc power systems is to provide an uninterruptible source of power to all normal and emergency 125 V-dc control and 250-V-dc power loads under all conditions.

8.5.2 SAFETY DESIGN BASIS

Each of the 125-V and 125/250-V batteries has adequate capacity to supply the vital unit loads without recharging for ~ 2 h.

Each battery charger has adequate capacity to restore its battery to full charge within 24 h from a discharged condition while carrying the normal unit steady state dc load.

The 125/250-V-dc power systems and the 125-V-dc emergency system are arranged so that no single component failure prevents the system from providing power to a sufficient number of dc loads necessary for safe shutdown.

The batteries and battery racks are Class 1E equipment to assure continuous operation of the equipment under maximum seismic shock conditions applicable to the area and location of the equipment.

Operating basis earthquake (OBE) and design basis earthquake (DBE) response spectrum curves for el 112 ft in the control building and for the diesel generator building established the seismic requirements of the plant batteries and the diesel generator batteries, respectively.

These batteries were shaker tested to verify their ability to meet the seismic requirements.

Battery racks have been specified and designed to meet seismic requirements appropriate to the building location. Vendor tests have verified the ability of the racks to endure a seismic event.

The battery racks are equipped with earthquake restraints to prevent the battery cells from falling from the racks.

A horizontal steel channel is installed along each side of the cells with spaced vertical members. End rails are also installed using bolted connections. These restraints are installed prior to seismic verification tests.

The 125/250 battery chargers shall conform to the applicable sections of the following IEEE Standards:

1. IEEE 344-1975, “Recommended Practices for Seismic Qualification of Class 1E Equipment”

2. IEEE 323-174, “Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations”

3. IEEE 829-1983, “IEEE Standard for Software Test Documentation”

4. IEEE 383-1974, “Qualifying Class 1E Electric Cables and Field Splices for Nuclear Power Generating Stations”

5. IEEE 384-1974, “Standard Criteria for Independence of Class 1E Equipment and Circuits”

6. IEEE 420-1973, “Design and Qualification of Class 1E Control Boards, Panels, and Racks Used in Nuclear Power Generating Stations”

7. IEEE 650-2006, “Qualification of Class 1E Static Battery Chargers and Inverters for Nuclear Power Generating Stations”

The 125/250 battery chargers shall conform to the applicable sections of the following Nuclear Regulatory Commission Regulatory Guides for Power Reactors:

1. Regulatory Guide 1.100, “Seismic Qualification of Electric Equipment for Nuclear Power Plants,” 1988

2. Regulatory Guide 1.180, “Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety Related Instrumentation and Control Systems,” 2003

3. Regulatory Guide 1.75 “Physical Independence of Electric Systems,” 1975

4. Regulatory Guide 1.210 “Qualification of Safety-Related Battery Chargers and Inverters for Nuclear Power Plants,” 1971

The 125/250 battery chargers shall conform to the applicable sections of the following Electric Power Research Institute Topical Reports:

1. EPRI TR-102323 “Guidelines for Electromagnetic Interference Testing in Power Plants,” 1997

8.5.3 DESCRIPTION

Two separate plant batteries are furnished, each with its own static-type battery chargers, circuit breakers, and bus. One spare battery charger is provided for each of the two batteries for servicing and to back up the two normal power supply chargers. Plant battery operating voltage is 125/250 V. Each battery with its main dc bus is in a separate room separated by a concrete wall. A Class 1 ventilation system for each battery room ensures operation during emergency conditions; fire dampers are installed in the ventilation duct system to prevent the spread of fire from one room into the other.

Batteries (1A and 1B) are 120-cell lead-calcium type with a continuous discharge rating of 1410 Ah and 1513 Ah, respectively, for 2 h at 77°F to 1.75 V final average cell voltage. These batteries are not tested at the 2 hour rate.

All six 125-V-dc battery chargers are full-wave silicon-controlled rectifier type rated 400 A with an output voltage regulation of ± 0.75% from no load to 2% load and ± 0.5% from 2% load to full load, with ac supply variation of ± 10% in voltage and ± 5% in frequency.

Five separate 125-V-dc power panelboards are provided. To maintain the required isolation and separation of the 600-V emergency systems, control power for each 600-V emergency bus is supplied from a separate battery. The system is shown on drawing no. H-13370.

Each of the two sets of batteries in the plant battery system has adequate storage capacity to carry the required load for an approximate 2-h period without recharging.

A separate 125-V diesel building battery is furnished for each diesel generator and its associated 4-kV bus. (See drawing no. H-13371.) Each battery has its own SCR type battery charger, circuit breaker, and bus with a spare battery charger for each battery to permit servicing or sparing any charger. Emergency battery operating voltage is 125 V.

Control power for each diesel generator, its generator breaker, and the associated 4-kV switchgear bus power feeder circuit breakers is supplied by its respective battery. Diesel battery 1A also supplies control power for 4160 V switchgear bus 1E and Division I loads on bus 1F. Diesel battery 1B also supplies emergency backup control power for 4160-V switchgear bus 1F, frame 7 (RHR pump 1D). Diesel battery 1C supplies control power for 4160-V switchgear bus 1G and Division II loads on bus 1F. Loads are as shown on figure 8.5-1.

Each of the diesel building batteries has adequate storage capacity to carry the required load for an approximate 2-h period without recharging. These batteries are 60-cell lead-calcium type with a discharge rating of 410 Ah for batteries 1A and 1C and 495 Ah for battery 1B for 8 h at 77°F to 1.75-V final average cell voltage.

All 125-V-dc chargers are full-wave silicon-controlled rectifier type rated 100 A with a voltage regulation of ± 0.75% from no load to 2% load and ± 0.5% from 2% load to full load with ac supply variation of ± 10% in voltage and ± 5% in frequency.

Following are characteristic of the station service and emergency diesel generator batteries:

The electrolyte is a mixture of sulfuric acid and water. The minimum design temperature for the electrolyte is 65°F for the station service batteries and 40°F for the diesel generator batteries. The minimum design electrolyte level is above the top of the plates but not overflowing. These limits are referenced in the Technical Specifications but the actual numbers are contained in the Battery Monitoring and Maintenance Program. Each battery is sized/designed with additional capacity above that required by the design duty cycles. This additional capacity includes corrections for temperature variations and aging, as well as other factors such as degraded design margin to support the use of float current monitoring to determine the state of charge of the battery. A dedicated design margin has been selected for this purpose which corresponds to a 20 amp float current value for the station service batteries and a 5 amp float current for the diesel batteries, indicating that the batteries are 95% charged.

These various margins are maintained within the design calculations.

During normal operation of the station service system, two of the three battery chargers are in service and the third is in standby. For the diesel generator DC system, one of the two battery chargers is in service and the second charger is in standby. The DC loads are normally powered from their battery chargers with the batteries floating on the system. On loss of power to the battery chargers, the DC system is powered by the batteries. Long term battery performance is obtained by maintaining a float charge greater than or equal to the minimum established design limits provided by the manufacturer.

For both the station service and diesel generator DC systems, while operating in the float mode, the batteries are maintained at greater than or equal to the minimum established float voltage of 132 V. This corresponds to one 125 V, 60 cell battery with all cells connected. If less than 60 cells are connected, the minimum established design float voltage would be based on 2.20 Volts per cell, times the number of connected cells.

The cooling tower battery system is a nonessential system composed of one 125-V battery and two 125-V battery chargers, one normal and one standby. The battery is a 60-cell lead-calcium type with a discharge rating of 100 Ah for 8 h at 77°F to 1.75-V final average cell voltage. The 125-V-dc battery chargers are full-wave rectified, saturable reactor type rated at 15 A and ±1% voltage regulation with an ac supply variation of ± 10% in voltage and ± 5% in frequency. The battery chargers, both normal and standby, are fed through a 120-V to 208-V cooling tower distribution panel from a 600-V to 208/120-V transformer. This transformer has two possible feeds, from either cooling tower bus 1G or 1H. Upon failure of the battery charger or its ac supply, dc power is supplied from the 125-V cooling tower battery. This system supplies control power for the cooling tower fan circuit breakers.

8.5.4 SAFETY EVALUATION

Power is normally supplied to the dc systems from the ac emergency buses of the auxiliary power distribution system through the battery chargers. Loss of either ac power source to any of the battery chargers causes the related battery to supply power to its dc loads. Each battery is capable of supplying adequate power to operate its loads during normal and emergency conditions. The related standby battery charger is then manually placed in service. The standby battery charger recharges the battery while supplying power to the loads. Each battery can be completely recharged from a discharged condition within 24 h.

The dc power panel boards and motor control centers (MCCs) that are associated with Division I are physically separated from Division II to meet the separation criteria given in section 8.8. In addition, each feeder has a breaker in the main dc power switchgear and a breaker in the MCC to provide a double breaker.

When the diesel generators are started for emergency service following loss of all normal ac power to the emergency buses, the batteries are supplying all dc power. The batteries have adequate capacity for 2-h operation before battery chargers need to be reenergized. The 125-V-dc station service battery chargers are connected to the 600-V emergency buses and can be reenergized manually as soon as the diesel generators are connected to the 4160-V buses. No manual action is required for the diesel generator battery chargers since they remain connected to the bus.

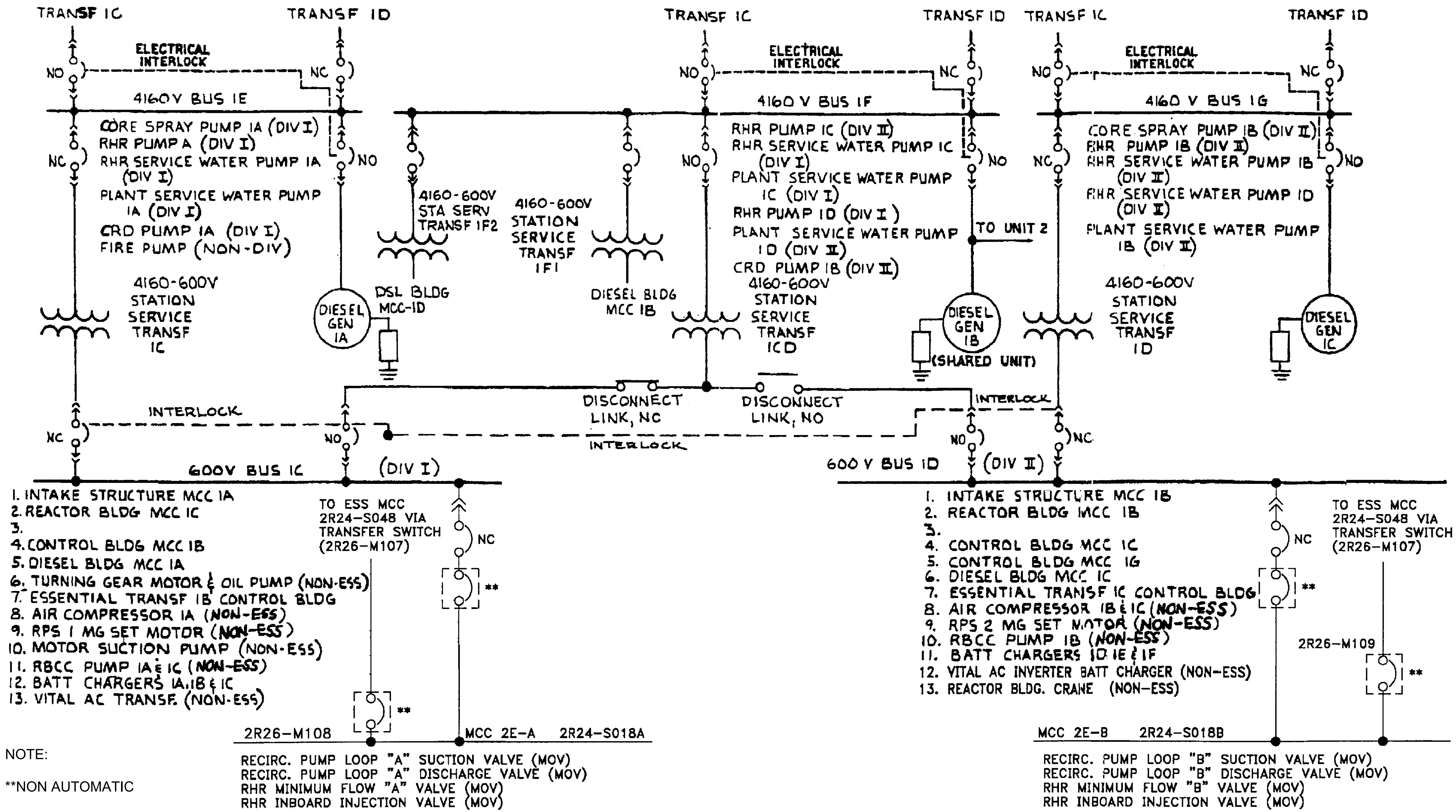
The 125-V and 125/250-V-dc systems are ungrounded with ground detectors which alarm in the main control room. Multiple grounds are not probable since the first ground would be located and removed as soon as possible after alarming in the main control room.

All batteries and battery racks are designed to Class 1E requirements, with the exception of the cooling tower batteries.

Although loss of one of the two ac sources is highly improbable, loss of one source would not prevent safe shutdown of the unit.

8.5.5 INSPECTION AND TESTING

The plant batteries and other equipment associated with the dc system are easily accessible for inspection and testing. Service and testing are accomplished on a routine basis in accordance with recommendations of the manufacturer. Typical inspections include visual inspections for leaks and corrosion, and the testing of all battery cells for voltage, specific gravity, and level of electrolyte.



NOTE:

**NON AUTOMATIC

REF DWG H-13361 REV 43
REF DWG H-13350 REV 17
REF DWG H-17012 REV 27

ACAD 1080501

REV 19 7/01

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LOAD ON 4160-V AND 600-V EMERGENCY BUSSES

FIGURE 8.5-1

8.6 24/48-V-dc POWER SYSTEM

8.6.1 POWER GENERATION OBJECTIVE

The power generation objective of the 24/48-V-dc power system is to provide uninterruptible dc power to neutron monitoring and process radiation monitoring instrumentation.

8.6.2 POWER GENERATION DESIGN BASIS

Two independent 24/48-V buses are provided, each supplied by a center point grounded 48-V battery and battery chargers which are fed from the emergency power buses. The batteries have adequate capacity to carry the instrument loads upon loss of ac power supply. The battery chargers have adequate capacity to recharge the batteries to full charge from a discharged condition in 8 h while carrying the normal connected load. Undervoltage relays initiate alarm in the main control room on low-voltage conditions.

The design basis for safe shutdown of the plant requires that absolutely no reliance be placed on the 24/48-V-dc system. Although the 24/48-V-dc system supplies power to neutron monitoring instrumentation, the loss of this system will not affect safe plant shutdown. In particular, the source range monitors do not have a scram function, while loss of the dc supply to the intermediate range monitors would result in multiple alarms and a reactor scram.

8.6.3 DESCRIPTION

A single line diagram for the 24/48-V-dc power system is shown on drawing no. H-13635. Each train has two batteries, two battery chargers, and a spare battery charger independent of each other. Under normal operation, the load requirements are supplied from the battery chargers with batteries floating. Upon failure of the ac supply to the chargers, the dc loads are supplied from the battery. Loss of one of the 24/48-V-dc trains does not affect plant safety since redundant instrumentation continues to be supplied by the second train. These batteries are 24-cell lead-calcium type with a continuous discharge rating of 75 Ah for 8 h at 77°F to 1.75-V final average cell voltage. The 24-V-dc battery chargers are full-wave silicon-controlled rectifier type rated 25 A and 0.5% voltage regulation with ac supply variation of 10% in voltage and 5% in frequency. Each 24/48-V train is provided with an undervoltage relay that alarms in the main control room if the voltage falls below a certain value.

All 24/48-V-dc batteries, battery chargers, and panelboards are non-Class 1E and, therefore, are not seismic.

8.6.4 INSPECTION AND TESTING

The batteries and chargers associated with the 24/48-V-dc system are readily accessible for inspection and testing. Service and testing is accomplished on a routine basis in accordance with recommendations of the manufacturer.

8.7 120/240 AND 120/208 V-ac POWER SYSTEM

8.7.1 POWER GENERATION OBJECTIVE

A. The 120/208-V essential ac power supply system is an essential power system. It supplies power to essential and nonessential loads. Failure of a nonessential load will not affect the ability of the system to supply power to the essential loads. It also serves as a backup supply to the reactor protection system (RPS).

B. The 120/208 V-ac instrument system supplies power to safeguard and nonsafeguard instruments, systems, and system auxiliaries. Failure of a nonsafeguard load will not affect the ability of the system to supply power to the safeguard systems.

C. The 120/240-V vital ac system provides power for vital services for which power interruption should be avoided. These vital services are necessary for the operation of the plant but are not required for plant safety.

D. The 120 V-ac RPS provides power to the RPS logic monitors.

8.7.2 POWER GENERATION DESIGN BASIS

The 120-V essential ac instrument system, as shown in figure 8.7-1, distributes adequate power to the main control room instruments, the 24-V battery chargers (described in section 8.6), and to all other loads. The system receives power from either of two ac sources.

The 120/240-V vital ac system, as shown in figure 8.7-1, has adequate capacity to power the computer and all other vital loads. Power is supplied from a static inverter or an ac source.

The 120-V RPS contains 2 ac motor-driven generators, each with adequate capacity to power the logic monitors of 2 trip channels. Alternate power is available to both RPS buses from the 120-V essential ac instrument system.

8.7.3 DESCRIPTION

The 120-V essential ac instrument system (figure 8.7-1) receives power from the auxiliary power distribution system described in section 8.3. Power is fed from either 600-V bus 1C or 1D. The instrument bus distributes power to all the conventional instrumentation and noncritical loads and monitors. The instrument power supply transformer is rated 112.5 kVA, 3 phase.

The 120/240-V vital ac system receives power from the static inverter which is supplied normally by a static battery charger connected to 600-V bus 1D. In case of loss of power on the 600-V bus, the inverter is automatically supplied from a separate battery. In case the static inverter fails, the vital ac system is automatically transferred to 600-V bus 1C. The vital ac system static inverter is rated 76 kVA, 120/240 V, ± 1% voltage regulation, and ± 0.5% frequency regulation.

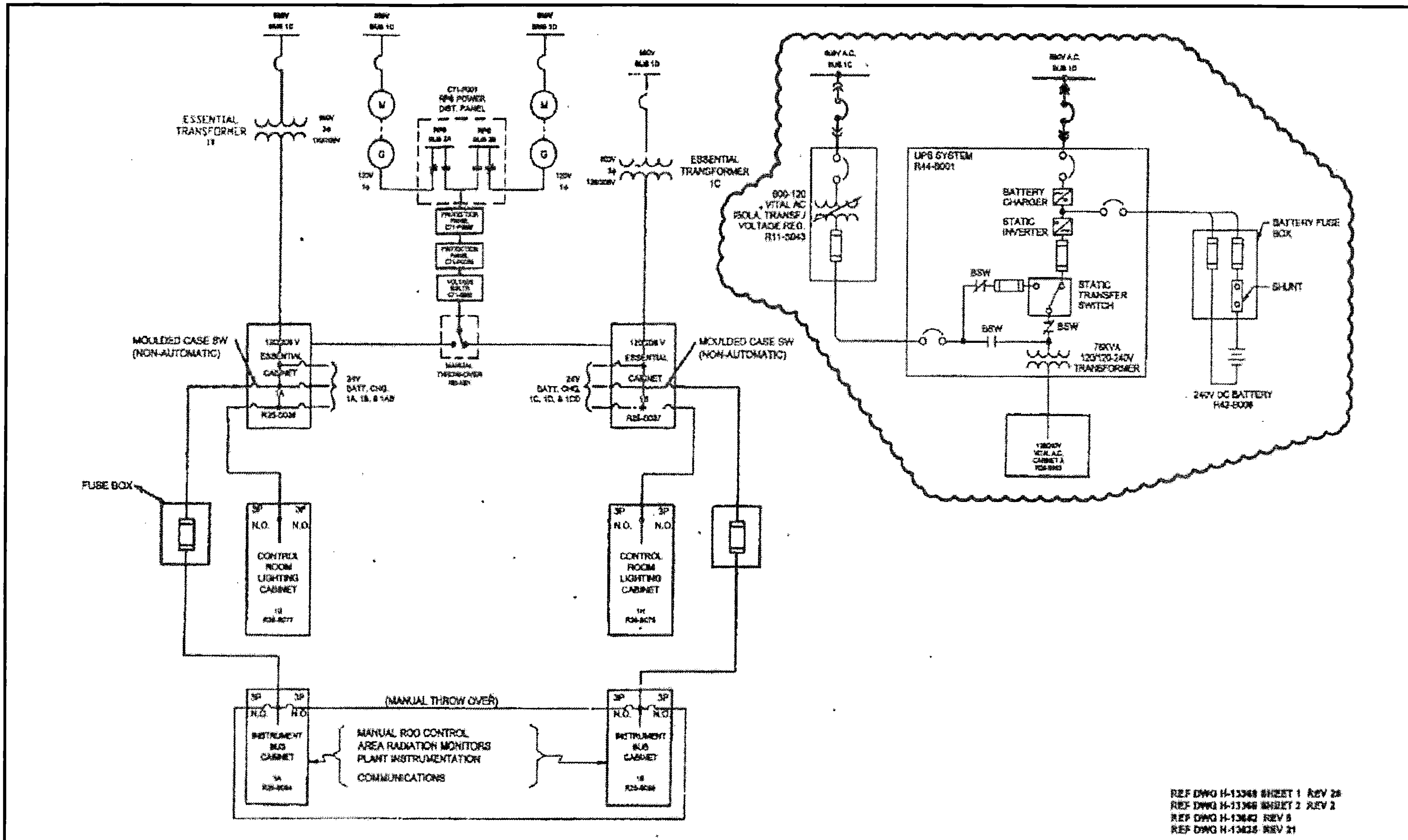
The 120-V RPS power supply system receives power from the auxiliary power distribution system described in section 8.3. Power is normally supplied from 600-V emergency service buses 1C and 1D through two motor-driven generators to two reactor protection logic monitor buses. Alternate power may be supplied manually to either bus through the 3-phase-600-120/208-V essential transformers. The reactor protection motor-generator sets are each rated 18.75 kVA.

The RPS buses also provide power supply for the analog transmitter trip system control panels.

The 120-VAC Critical Instrument Buses comprise an essential power system supplied from the safety-related 125/250VDC system via safety-related, seismically qualified 7.5 kVA, 250 VDC/120 VAC Inverters. Like the essential 120/208 VAC instrument buses, the critical instrument buses supply both essential and non-essential loads. They provide AC power from the safety-related DC sources to loads critical for the mitigation of events when AC power is not available from offsite sources or from the on-site emergency AC system. Failure of a non-essential load will not affect the ability of this system to supply the essential loads. Back-up power is available to the inverter via the existing essential cabinets. The back-up power will ensure power is not lost to the critical instrumentation during DC system maintenance.

8.7.4 INSPECTION AND TESTING

Inspection and testing at vendor factories were to ensure that all components were operational within their design ratings.



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120-208/120-240-V-ac
POWER SYSTEM

FIGURE 8.7-1

8.8 CABLE DESIGN AND ROUTING OF CIRCUITS

8.8.1 SAFETY OBJECTIVE

It is a safety objective to provide a cable system with cables and penetrations selected, routed, and located to survive the design basis events established for this plant and prevent a loss of function of any system due to a cable failure.

8.8.2 SAFETY DESIGN BASES

A. The design criteria for cable, cable tray support, instrument racks, control consoles, electrical penetrations (described in chapter 5), and circuit routing have been established to prevent a failure in electrical cable and penetration systems from initiating a fire, and to minimize and localize the effect of fire should one occur. These criteria are set by the following provisions:

- Cable construction.
- Sizing of power cables.
- Design criteria for the cable spreading room.
- Electrical penetration design.
- Cable routing.
- Spacing of cables in cable trays.
- Circuit protection.
- Cable tray support systems.
- Instrument racks and control consoles.
- Fire protection and detection systems.

B. Class 1E cables to engineered safeguard equipment within the primary containment are designed to withstand, without loss of function, the environmental conditions resulting from any design basis event.

8.8.3 DESCRIPTION

8.8.3.1 Cable Construction

All electrical conductor insulation is of flame-retardant construction except for some of the instrumentation and communication cables. IEEE-383 was not in existence at the time cable was purchased for the construction of HNP-1. The cable purchased met the state-of-the-art as it existed at that time with respect to flame retardance. Except for some instrumentation and communication cables, all insulation is XLPE, okonite rubber, or ethylene propylene rubber (EPR). Except in special instances and where specifically justified, all cable currently being purchased for use within the power block at HNP must meet IEEE-383 flame tests.

The insulation described above has superior electrical and physical characteristics, and the materials are thermally stable compounds which do not melt when subjected to temperatures well beyond their operating ranges. This property permits the cable to perform its designated function even after having been subjected to severe environmental conditions.

8.8.3.2 Sizing of Power Cables

Ampacity rating of cables is established as published in IPCEA P-46-426 and in accordance with the manufacturer's standards. To this basic rating, a grouping derating factor, also in accordance with IPCEA P-46-426, was applied. Wherever applicable, a load diversity factor was taken into consideration. As a minimum, all power cables were selected utilizing an 80% load diversity factor and continuously rated at 125% of the full-load current.

8.8.3.3 Design Criteria for the Cable Spreading Room

All cables in the cable spreading room associated with the nuclear protection and engineered safeguards systems are arranged so that redundant circuits for each of the individual systems are isolated either by physical separation or fire barriers where physical separation cannot be maintained to completely prevent the spread of fire in any one tray or conduit system to other redundant circuits of the same system. In addition to the utilization of physical separation and firebarriers, a manual CO_2 and automatic H_2O fire protection system has been installed complete with fire detectors and alarms.

Fluid system piping, rotating equipment, power switchgear, distribution panels, protection and engineered safety feature instrumentation, control racks, power cables (600 V-ac, 250 V-dc or larger), and panels are not located or routed in the cable spreading room. Ducts required to recirculate or exhaust air from the cable spreading room and the piping for the fire protection system are permitted.

No material is stored in the cable spreading room.

The cable spreading room is a controlled access area. Entry is controlled through the security system and an alarm system annunciating in the main control room.

8.8.3.4 Penetrations

The power, control, and instrument cables pass through the primary containment wall in electrical penetrations which are described in chapter 5.

- The criteria for the separation of electrical penetration are as follows:
- No intermixing of 4160-V and 600-V cables in the same penetration.
- No intermixing of the above power cables with other cables in the same penetration.
- No intermixing of cables associated with redundant equipment in the same penetration.
- A minimum of 2-ft arc length is maintained between the centerlines of electrical penetrations carrying cables of the same division and voltage level. Penetrations for redundant systems are located no < 90 degrees apart on the containment.

The electrical penetration assemblies are capable of withstanding a direct jet force of saturated steam of 1250 psig and 300°F over the full-projected interior areas of the assembly for 200 s and still maintain their leaktight integrity.

One of each type of power penetration, calculated to have the worst-case loadings was given a thermal test with rated current on all conductors.

Prototype testing of penetration designs similar to those used for Hatch Nuclear Plant-Unit 1 (HNP-1) was performed under the following environmental conditions:

Temperature (°F)	340	340	320	250	200
Pressure (psig)	63	35	35	25	20
Relative humidity (%)	100	100	100	100	100
Duration (cumulative)	15 min	3 h	6 h	1 day	1 1/2 days

The environmental conditions indicated above were supplied to the primary containment side inboard seal of the penetration assembly while conductors were loaded to produce 15 W of heat per foot of penetration lengths. This test assures that the penetration assembly maintains containment integrity and that the required appropriate cables, during and after the abnormal conditions, survive the environmental conditions listed above with no loss of function.

Conductors inside the penetration are applied with consideration to the aforementioned application criteria, the number of circuits, the load factor, and the ambient temperature within the penetration. Test data have been obtained to determine the off-gassing properties of the conductor insulation. The method of applying cables and the test performed on insulation assures that off-gassing within the penetration does not occur. Tests are performed to assure that all connections are made properly. The connections and conductors are fully insulated. No soldered connections are used for power wiring.

After the penetrations are installed, they are evacuated and filled with a dry inert gas to assure that moisture is not present. Final leak checks are performed. The penetration manufacturer makes available trained field engineers to assist in the installation and checking of the penetrations.

The purpose of IEEE-317 is to provide guidance in determination of the features of design related to primary containment electrical penetrations of nuclear facilities and, as such, the detailed characteristics of a given primary containment penetration design lead to different interpretations.

The HNP-1 primary containment electrical penetrations are manufactured by General Electric (GE), with the exception of T52-X100G/H and T52-X100I/J, which are manufactured by Conax. The GE design involves two header seals in each penetration, one inboard to the reactor pressure vessel (RPV) and one outboard to the primary containment wall. The outboard seal would never be directly exposed to the adverse conditions following an accident. Tests described under paragraphs 5.1.2, 5.1.4, 5.1.5, and 5.1.7 of IEEE-317 were not performed at service environment conditions. As indicated in paragraph 8.8.3.4, the environmental conditions for prototype testing were applied to the inboard seal inside the primary containment. Testing under the service environment conditions is not necessary for the outboard seal since it only sees ambient conditions. The dual seal design completely satisfies the intent of IEEE-317.

The Conax design uses sealed conductor feedthrough assemblies, which are mounted and sealed in a header plate. The conductors passing through each feedthrough assembly are sealed at each end of the feedthrough housing. Metal compression fittings are used for mounting the conductor feedthrough assemblies to the header plate in a double-sealed manner. The header plate forms the pressure-retaining boundary interfacing with the conductor module and the containment wall. A prototype penetration was subjected to all applicable design and qualified life tests as defined by IEEE-317.

8.8.3.5 <u>Cable Routing</u>

The cable pullcards show the routing of each circuit with respect to the trays and conduits, the cable termination drawing numbers (wiring diagrams), the type of cable used, and the system with which each cable is associated. Coded symbols identify all safety-related cables.

The cable pullcard information and updated wiring diagrams are maintained on file with the plant operating and maintenance personnel to provide a permanent record of the detailed routing of all cables and terminations thus assuring that the design criteria are maintained throughout the life of the plant.

A. In rooms or compartments outside the containment having an operating crane or rotating heavy machinery, or in rooms containing high-pressure piping or high-pressure steam lines, there is a minimum separation of 20 ft, or a 6-in.-thick reinforced concrete wall is required between equipment or trays or exposed conduits containing cables of redundant systems; that is, unless confirming analysis to support less stringent requirements is made.

B. Instrument racks which are redundant to one another are located a minimum of 5 ft apart, and Class 1 redundant racks in hostile areas are separated by suitable barriers. Instrument racks for the RPS which are redundant are located on opposite sides outside the primary containment.

C. Where vertical shafts are used between elevations, the same philosophy of separation is followed. In addition, all cable openings between elevations are sealed.

D. All cables entering the cable spreading room and control room areas and interconnecting cables between these two rooms are sealed by 3-h fire-rated materials to assure the integrity of each area.

The design of cable runs within the plant adheres to the following practices.

8.8.3.5.1 Raceway/Cable Color Codes

A. Raceway and cable associated with the safety-related systems shall be identified so that two facts are physically apparent to operating and maintenance personnel:

   1. The raceway or cable is part of the reactor protection system (RPS), primary containment isolation system (PCIS), or engineered safety system (ESS) equipment.

   2. The division of enforced segregation with which the raceway and cable is associated.

B. Color codes for cables and raceways are shown in table 8.8-1.

C. Cables shall be paint marked by divisional color at intervals not to exceed 10 ft, except for RPS and PCIS cables which have red tags at terminating points.

   Cables shall be tagged at each end. The tags shall give the cable number and divisional color information as a minimum.

D. Trays are identified by "EZ" code markers at intervals not exceeding 15 ft. Each marker has the tray number annotated on the divisional color background. All conduits have numbers written at both ends and/or both sides of penetrations.

RPS and PCIS cables are routed in conduits which have red tapes marked at an interval not exceeding 15 ft, in addition to the conduit number marked adjacent to the tape.

8.8.3.5.2 Physical Identification of Safety-Related Equipment

The RPS and engineered safeguard equipment are physically identified by devices such as nameplates. Sufficient identification is included such as name and equipment number of the apparatus and applicable channel or safety division.

8.8.3.5.3 Separation Requirements

8.8.3.5.3.1 <u>System Separation Requirements.</u> In the absence of confirming analysis to support less stringent requirements, the following rules shall apply to system separation.

A. RPS and PCIS

1. Cables for RPS and PCIS outside the main electrical equipment enclosures are run in rigid metal or flexible ferromagnetic (6 ft or less) conduit used for no other purpose. Under vessel neutron monitoring cables are exempt from the above requirement because of space limitations and need for flexibility on intermediate range monitor (IRM) cables.

2. The PCIS has four channel allocations, namely IA, IB, IIA, and IIB. The RPS has four to six channel allocations, namely IA, IB, IIA, IIB, IIIA, and IIIB.

   Designations RPS IIIA and RPS IIIB have been used to identify the circuits used for manual scram and dc backup scram to the pilot air header dump valves.

   This identification is functional; i.e., manual versus automatic, and does not modify the concept of the four channel RPS. Each of these channels shall be routed in separate conduit, except RPS IIIA and RPS IIIB routed with RPS IA and RPS IIB, respectively.

3. Where RPS and PCIS cables of an identical channel run between the two same points, they may share the same conduit.

4. The four reactor protection scram solenoid group circuits shall not mix with each other or with any other RPS, PCIS, or essential division circuit.

B. ESS Systems

All cables for ESS are routed only in raceways of the same ESS division as the cable.

C. Emergency Diesel Generator Systems

All emergency diesel cables are routed in raceways of the same division as the cable or in ESS raceways as follows:

Diesel	ESS Division
A	I
B	II
C	II

Diesel B cables shall be routed in separate raceways from diesel A and diesel C cables.

D. Cable/Raceway Compatibility

Table 8.8-2 shows the circuit separation code, allowable raceway code, and cable color codes to meet the aforementioned separation criteria.

E. All Other Systems

Nonsafety-related cables may be routed in ESS division raceways, but a cable may not be routed from one division to another. All cables have adequate overload and short circuit protective features to ensure that nonsafety-related cables do not jeopardize the integrity of the safety-related cables.

8.8.3.5.3.2 **Physical Separation Requirements.** This section establishes the criteria for preserving the independence of redundant essential systems and associated circuits.

A. A cable tray designated for cables with a particular voltage classification contains only those cables of the same voltage classification.

B. Cables associated with each safety-related separation group are run in separate conduits, cable trays, ducts, and penetrations unless an analysis is performed to support less stringent requirements. (See figure 8.8-1 for the schematic diagram of the divisional raceway.) Barriers are provided in the pull boxes to maintain physical separation.

C. The arrangement of electrical equipment and cabling minimizes the possibility of a fire in one separation group from propagating to another separation group.

Areas in which the potential damage is limited to failures or faults internal to the electrical equipment are divided into the following areas:

1. General Plant Areas

2. Cable Spreading Room

   In the absence of confirming analysis to support less stringent requirements, the following rules apply:

   a. General Plant Areas

      (1) Vertically stacked trays of the same division are generally installed with a minimum vertical separation of 12 in. between the top of the lower tray and the bottom of the upper tray. The horizontal separation between trays of the same division is a minimum of 6 in. between the interior sides of the trays.

      (2) The vertical separation between two stacks of trays of different divisions is 5 ft from the top of the topmost tray of the lower stack to the bottom of the lowest tray of the upper stack. In areas where this requirement is not attainable, the topmost tray of the lower stack must have either a solid metal cover or 1 in. of Kaowool laid in. The lowest tray of the upper stack must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 5-ft separation between trays is achieved or to the wall.

      (3) The horizontal separation between trays of different divisions is a minimum of 3 ft between the interior sides of the trays of both divisions. In areas where this requirement is not attainable, both trays must have either a solid metal cover or 1 in. of Kaowool laid in on the top. Both trays must also have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 3-ft separation is achieved or to the wall or floor.

      (4) When stacks of trays of different divisions cross each other, the vertical separation is 5 ft from the top of the topmost tray of the lower stack to the bottom of the lowest tray of the upper stack. In areas where this requirement is not attainable, the topmost tray of the lower stack must have either a solid metal cover or 1 in. of Kaowool laid in. The lowest tray of the upper stack must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on

the bottom. These covers or Kaowool shall extend 3 ft from each side of the intersection or to the wall or floor.

(5) Where conduits of one division cross over or run parallel above a cable tray of the opposite division, there shall be a minimum vertical separation of 5 ft. In areas where this requirement is not attainable, the tray must have either a solid metal cover or 1 in. of Kaowool laid in, or the conduit must be wrapped with 1 in. of Kaowool. For crossover, this cover or Kaowool shall extend 3 ft from each side of the intersection or to the wall. For parallel runs, this cover or Kaowool must be installed to a distance where the 5-ft separation is achieved or to the wall.

b. Cable Spreading Room

(1) The vertical separation between trays of different divisions is 3 ft from the top of the lower tray to the bottom of the upper tray. In areas where this requirement is not attainable, the lower tray must have either a solid metal cover or 1 in. of Kaowool laid in. The upper tray must have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 3-ft separation between trays is achieved or to the wall.

(2) The horizontal separation between trays of different divisions is a minimum of 1 ft between the interior sides of the trays of both divisions. In areas where this requirement is not attainable, both trays must have either a solid metal cover or 1 in. of Kaowool laid in on the top. Both trays must also have one of the following: a solid metal bottom, a solid metal cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool must be installed to a distance where the 1-ft separation is achieved or to the wall or floor.

(3) Where trays of different divisions cross each other, the vertical separation is 3 ft from the top of the lower tray to the bottom of the upper tray. In areas where this requirement is not attainable, the topmost tray of the lower stack must have either a solid metal cover or 1 in. of Kaowool laid in. The lowest tray of the upper stack must have one of the following: a solid metal bottom, a solid metal tray cover installed on the bottom, or 1 in. of Kaowool installed on the bottom. These covers or Kaowool shall extend 1 ft from each side of the intersection or to the wall or floor.

(4) Where cables of different divisions approach the same or adjacent panels with spacing less than the minimum specified above, at least one of the cables (or group of cables) shall be run in metal (rigid or flexible) conduit to a point where the required separation exists.

(5) Where conduits of one division cross over or run parallel above a cable tray of the opposite division, there shall be a minimum vertical separation of 3 ft. In areas where this requirement is not attainable, the tray must have either a solid metal cover or 1 in. of Kaowool laid in, or the conduit must be wrapped with 1 in. of Kaowool. For crossovers, this cover or Kaowool shall extend 1 ft from each side of the intersection or to the wall. For parallel runs, this cover or Kaowool must be installed to a distance where the 3-ft separation is achieved or to the wall.

8.8.3.5.3.3 **Separation of Electrical Equipment.** This section defines the requirements for the separation of wiring and components within an electrical enclosure (such as a panel) and between two redundant pieces of electrical equipment.

In the absence of confirming analysis to support less stringent criteria, the following rules shall apply:

A. Separation of RPS and PCIS Circuits and Electrical Equipment

1. The four reactor protection scram solenoid group circuits shall not mix with each other or with any other RPS, PCIS, or essential division circuit.

2. The RPS and PCIS circuit and components within a single piece of electrical equipment shall be allowed to mix as follows:

Group A	Group B
RPIA	RPIIA
RPIB	RPIIB
PCIA	PCIIA
PCIB	PCIIB
RPIIIA	RPIIIB

Mixing of Group A with Group B shall not be allowed.

3. Where the above criteria cannot be met, there must be a minimum of 6 in. of separation between circuits or electrical equipment. Where it is impractical to provide physical separation:

a. The cables must be separated by a metal barrier or enclosed in metal conduit.

b. Instrumentation and control cables (≤ 125 V) not subject to harsh environments may be wrapped with an approved barrier material to provide thermal and electrical insulation.

c. The electrical equipment must be separated by a metal barrier or enclosed in metal enclosure.

B. Separation of ESS Circuits and Electrical Equipment

1. ESS-I and ESS-II circuits shall not mix with each other.

2. Where the above criterion cannot be met, see paragraph 8.8.3.5.3.3., item A.3.

C. Nonessential Associated Circuits

1. In the case where the nonessential wiring associated with one division terminates in the same equipment as the essential wiring of the other division, the nonessential cables are treated as essential and separation is provided as delineated above.

2. No separation is required where nonessential associated wiring of one division terminates in the same equipment as nonessential associated wiring of another division.

D. If two pieces of redundant electrical equipment are < 3 ft apart, there shall be a steel barrier between them. Panel ends closed by metal end plates are considered to be acceptable barriers.

8.8.3.6 <u>Spacing of Cables in Cable Trays</u>

As a minimum requirement, all power cable trays are limited to a 40% fill by cross section. In addition, all 4-kV and 600-V cables 1/0 and above have as a minimum one cable diameter spacing between all cables in the same tray. Where smaller, 600-V cables share the same tray with those 1/0 and above, barriers are installed in the tray to ensure the spacing of the larger cables.

Power cables are secured by ty-wrap at intervals not to exceed 8 ft in horizontal trays and 4 ft in vertical trays.

8.8.3.7 Circuit Protection

All ac power feeders and ac control power feeder cables are protected by circuit breakers. (No fused protection is used for the protection of any power or control of power feeder.)

8.8.3.8 Cable Tray Supports

Cable tray supports are designed to withstand dead loads plus seismic loads. Paragraph 12.3.3.2.1.4 discusses the seismic design bases for cable tray supports.

8.8.3.9 Instrument Racks and Control Consoles

The seismic design criteria to assure the adequacy of Class 1 instrument racks and control consoles were accomplished by static analytical procedures and/or vibration testing.

Static Analysis

The static analysis included the following combination of equivalent seismic coefficients acting at the center of mass applied simultaneously in the most disadvantageous direction.

	Horizontal	Vertical
Operating basis earthquake (OBE)	0.75 g	0.07 g
Design basis earthquake (DBE)	1.50 g	0.14 g

Vibration Testing

The acceleration used in vibration testing of critical instrumentation to assure no loss of safeguards function exceeded the maximum accelerations expected from building motions.

The values used for vibration testing at the points of attachment are equivalent to 1.50-g horizontal and 0.50-g vertical over the frequency range of 5 to 33 Hz.

Seismic Restraints

The methods of seismic restraint include the design of the anchorage systems, welded stiffners, cross bracing, and lateral supports to the building. Stresses due to seismic forces in combination with other design stresses do not exceed the allowable design stresses and stiffness requirements, as applicable, are met.

8.8.3.10 Fire Protection and Detection Systems

In addition to the fire protection and detection measures mentioned in paragraphs 8.8.3.3 and 8.8.3.5, the ***Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR)***, submitted to the Nuclear Regulatory Commission on July 22, 1986, contains a description of fire protection and detection system.

8.8.4 SAFETY EVALUATION

All cables have adequate flame resistant properties and are designed to resist radiation, high temperature, and high-humidity levels in the area in which they are installed. Power and control cables to safeguard equipment within the primary containment are designed to withstand the environmental conditions caused by an accident. The current-carrying capacity of all power cables is conservatively calculated to preclude thermal overload. Intermixing of power, control, and instrumentation cables in raceways or in penetrations is not permitted, except in the case of annunciator cables, which may be mixed with control cables, but not with power cables. Cables of redundant circuits are physically separated by means of space, fire barriers, concrete walls or floors to assure maximum independence of redundant channels. Cables are installed in either conduits or cable trays.

8.8.5 INSPECTION AND TESTING

During construction, inspection and testing at the vendor factories and initial system tests were conducted to ensure all cable material and completed cables were operational within their design rating. Inspections are conducted on selected cables supplying power to equipment important to safety that have been in service for some time to detect any deterioration in cable materials that might occur.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.

TABLE 8.8-1

CABLE AND RACEWAY COLOR CODES

System	Color Code for Cables	Color Code for Raceways
RPS and PCIS cables	Red tags (at the terminal points)	Red tape
Engineered safeguard system divisional I cables	Yellow	Yellow
Nondivisional cables in division I raceways	Blue	Yellow
Diesel 1A cables	Yellow	Yellow
Engineered safeguard system divisional II cables	Green	Green
Nondivisional cables in division II raceways	Orange	Green
Diesel 1B cables	White	White
Nonclassified cables in diesel 1B raceways	Orange on white	White
Diesel 1C cables	Violet	Green

TABLE 8.8-2

CABLE/RACEWAY COMPATIBILITY (HNP-1)

Circuit Separation Code	Allowable Raceway Codes			Cable Color Codes: Divisional	Cable Color Codes: Non-Divisional	Separation Check Procedure[(a)]
DUMMY						
ESA	ESI	ESA		Yellow		1
ESB	ESC	ESII	ESB	White	Ora-wht	3
ESC	ESB	ESII	ESC	Violet		3
ESI	ESI	ESA		Yellow	Blue	1
ESII	ESB	ESC	ESII	Green	Orange	4
NONDIV	ESI	ESA	NONDIV	Nondiv	Nondiv	1
NONDIVA	ESII	ESC	NONDIV			1
NONDIVB	ESII	ESB	NONDIV			1
PCIA	PCIA	RPIA	RP3A	Red		1
PCIB	PCIB	RPIB		Red		1
PCIIA	PCIIA	RPIIA		Red		1
PCIIB	PCIIB	RPIIB	RP3B	Red		1
RPIA	RPIA	PCIA	RP3A	Red		1
RPIB	RPIB	PCIB		Red		1
RPIIA	RPIIA	PCIIA		Red		1
RPIIB	RPIIB	PCIIB	RP3B	Red		1
RP3A	RP3A	RPIA	PCIA	Red		1
RP3B	RP3B	RPIIB	PCIIB	Red		1

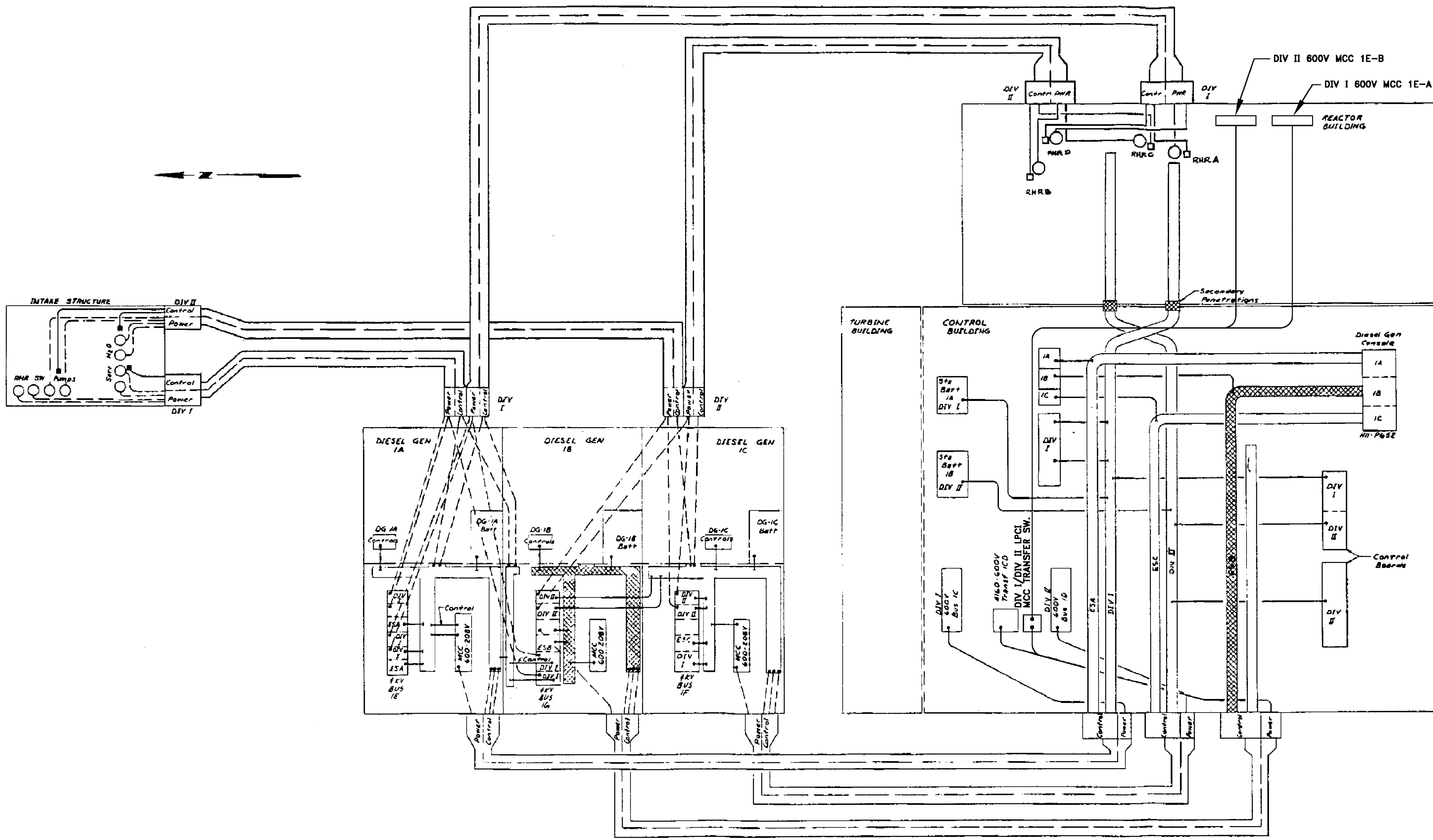
a. Procedure Description

1. The separation code for each raceway in the circuit path must be an allowable raceway code for the circuit separation code for the circuit being routed. For nondiv circuits, the separation criteria are satisfied if the above condition is met by either the nondiv, nondiva, nondivb separation code record.

2. Separation codes for raceways in the circuit path must be allowable raceway codes for the circuit separation code for the circuit being routed. Routing is rejected, however, if raceways with separation codes equal to both the first and second allowable codes are in the path.

3. Separation codes for raceways in the circuit path must be allowable raceway codes for the circuit separation code for the circuit being routed; each circuit in each raceway in the circuit path is examined. Routing is rejected if the path has a raceway with separation code equal to the second allowable code and contains circuits with separation code equal to the first allowable code (this includes the circuit being routed). Routing is also rejected if the separation code for one of the raceways is equal to the first allowable raceway code.

4. Each raceway in the proposed path and all circuits (including the circuit to be routed) in those raceways are examined. Routing is rejected if separation codes equal to both the first and second allowable codes for the circuit separation code of the circuit being routed are found. The separation code for each raceway in the circuit path must be an allowable raceway code for the circuit separation code of the circuit being routed.



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UNIT 1

SCHEMATIC DIAGRAM OF DIVISIONAL RACEWAYS

FIGURE 8.8-1

8.9 FIRE DETECTION AND ALARM SYSTEM

The plant fire detection and alarm system is described in the ***Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR)***.

8.10 CLASS 1E ELECTRICAL EQUIPMENT NOT SUPPLIED BY GENERAL ELECTRIC

The following Class 1 electrical equipment was procured from vendors other than General Electric nuclear steam supply system vendor:

- 4160-V switchgear.
- 600-V switchgear.
- 125/250-V-dc switchgear.
- Motor control centers.
- The ac and dc distribution cabinets.
- Batteries and racks, and battery chargers.
- Instruments and equipment mounted on control and relay panels.
- Diesel generator neutral grounding resistor.
- 125-V-dc transfer switch.
- Diesel generator.
- Electrical penetrations.
- 225-kVA diesel building transformer.
- Control and relay panels.

All of the above equipment, with the exception of the last four bulleted items, were tested seismically.

Due to the size of the diesel generators, a complete mathematical analysis was performed to verify the ability of this equipment to withstand the earthquake.

In case of electrical penetrations, use of a mathematical model allowed imposition of more stringent requirements, thus producing a more conservative design. The mathematical model is acceptable as a means of meeting the American Society of Mechanical Engineers Code.

A rigorous mathematical analysis for the diesel generator transformer was considered adequate.

Control panels were mathematically analyzed. Individual instruments and equipment mounted on the panels were tested. This approach was considered rigorous and adequate.

The seismic analyses for the components and the panels were reviewed by Bechtel Corporation and Southern Company Services, Inc.

8.11 STATION BLACKOUT (SBO)

See HNP-2 FSAR section 8.4 for a discussion of Plant Hatch's SBO coping evaluation.

9.0 RADIOACTIVE WASTE SYSTEMS

9.1 SUMMARY DESCRIPTION

The radioactive waste systems are designed to collect, process, and dispose of potentially radioactive wastes produced during the operation of the plant. These wastes are grouped as liquid, gaseous, or solid wastes.

The liquid radwaste system is designed to process and recycle the liquid waste collected in the waste holdup tank to the extent practicable. Liquid waste collected in chemical or floor drain tanks is normally discharged to the environment after treatment and dilution. During normal plant operations, the annual radiation doses to individuals from each reactor on the site, resulting from these routine liquid waste discharges, are within the 10 CFR 50, Appendix I, design objectives. Short-term releases from the plant resulting from equipment malfunctions or operational transients are within the limits specified in the Radioactive Effluent Controls Program.

Solid waste is packaged in suitable containers for offsite shipment and disposal or for storage onsite at the low-level radioactive waste (LLRW) storage facility.

The wet solid radwaste system is a continuous part of the liquid radwaste system. The wet solids, consisting of spent demineralizer bead resins and powdered filter resins, are pumped in slurry form to the resin dewatering and packaging system for offsite shipment. The resin dewatering and packaging system is described in the HNP-2-FSAR subsection 11.5.5.

Dry solid radwaste, consisting of contaminated air filters, miscellaneous paper, rags, clothing, tools, wood, etc., is collected in containers located in appropriate areas of the plant. The filled containers are sealed and moved to the waste separation and temporary storage facility (WSTSF) for processing and disposal. The WSTSF is described in the HNP-2-FSAR subsection 11.5.6.

The air ejector off-gas radioactive waste is treated by an ambient charcoal bed adsorption system before discharge to the environment. The annual dose at or beyond the site boundary due to gaseous effluents from each unit during normal operation does not exceed the 10 CFR 50, Appendix I, design objectives.

The liquid and gaseous effluents from the treatment systems are continuously monitored, and the discharges are terminated if the effluents exceed preset radioactivity levels.

The radioactive waste treatment system design discussed in this section limits the radioactivity releases to the environment from HNP to levels as low as reasonably achievable.

HNP-2-FSAR subsection 3.8.7 provides seismic evaluations of the radwaste facilities buildings. The results of the seismic evaluations are also applicable to HNP-1.

9.2 LIQUID RADWASTE SYSTEM

All information supplied in the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) Final Safety Analysis Report (FSAR) section 11.2 is applicable to HNP-1 with the following exceptions.

9.2.1 SYSTEM DESCRIPTION

Refer to HNP-2-FSAR subsection 11.2.2 for the system description. Figure 9.2-1 is a block diagram identifying important pieces of equipment and main process flow for HNP-1. Differences exist between the HNP-1 and HNP-2 flowpaths. The arrangement of radwaste system equipment for HNP-1 is shown on drawing nos. H-12626, H-12628, H-12632, H-15851, H-15852, H-15854, H-16027, H-16033, and H-16036. The liquid radwaste system piping, equipment, instrumentation, and flowpaths for HNP-1 are shown on drawing nos. H-16176 through H-16182, and H-16517.

9.2.1.1 High-Purity Wastes

Refer to HNP-2-FSAR paragraph 11.2.2.1.1. The exception is that the off-gas equipment process sump and the waste gas treatment building equipment drain sump are not inputs to the HNP-1 high-purity liquid wastes.

9.2.1.2 Low-Purity Wastes

Refer to HNP-2-FSAR paragraph 11.2.2.1.2. The exception is that the off-gas pipe trench floor drain sump is not an input to the HNP-1 low-purity liquid wastes.

9.2.1.3 Chemical Wastes

Refer to HNP-2-FSAR paragraph 11.2.2.1.3. Laboratory and hot shower wastes are also collected in the chemical waste tank of HNP-1.

9.2.1.4 Laundry Wastes

Laundry wastes for both HNP units are processed by HNP-1. Laundry wastes, which consist primarily of laundry drains and other drains which may contain detergents, are collected in the drain tank. Laundry wastes normally are of low-radioactivity concentration. Because these wastes foul ion exchange resins due to the detergents, they are kept separate. They are filtered through the laundry drain filter, diluted, and discharged into the circulating water discharge canal.

9.2.1.5 Miscellaneous Liquid Waste

Water drained from the dryer separator pool and reactor well after refueling is discharged via the spent-fuel pool cooling and demineralizer system to the condensate storage tank (CST).

Excess reactor vessel water may be removed via the reactor water cleanup (RWC) demineralizer system and discharged to the radwaste waste collector tank or waste surge tank; however, it normally is routed to the main condenser hotwell from whence it passes through the condensate demineralizer system.

A waste surge tank is provided in the radwaste system to increase the capacity of the waste collector system by collecting the water from system surges and providing interim storage for recycled waste.

9.2.2 PROCESS EQUIPMENT DESCRIPTION

Refer to HNP-2-FSAR paragraph 11.2.2.2 for a description of components. Design codes for major components in HNP-1 are provided in table 9.2-1. HNP-1 tank capacities and maximum radioactive isotope content are given in table 9.2-2.

9.2.3 ESTIMATE OF RADIONUCLIDES EXPECTED TO BE RELEASED

HNP-2-FSAR subsection 11.2.4 discusses the methodology and data used in obtaining expected isotopic liquid releases for Plant Hatch. HNP-2-FSAR table 11.2-3 lists the input used in the BWR-GALE Code. HNP-2-FSAR table 11.2-4 gives the resulting annual liquid releases, including effluent from laundry waste processing, which is performed by HNP-1.

9.2.3.1 Estimated Doses

HNP-2-FSAR subsection 11.2.4 describes the dose calculation metholology used and the resulting data, and discusses compliance with the design objectives of 10 CFR 50, Appendix I. HNP-2-FSAR table 11.2-5 outlines maximum individual doses based on the releases listed in HNP-2-FSAR table 11.2-4.

TABLE 9.2-1

DESIGN CODE FOR MAJOR LIQUID RADWASTE SYSTEM COMPONENTS

Piping	American National Standards Institute (ANSI) B31.1.0 - 1967
Valves	ANSI B31.1.0 - 1967
Pumps	Manufacturer's standard
Filters	American Society of Mechanical Engineers (ASME), Section III, Class 3 and ASME, Section VIII, UW-2(a) (1968)
Demineralizers	Nuclear Class C vessel built in accordance with ASME Boiler and Pressure Vessel Code, Section III (1968) and Section VIII, Division 1 (1968)
Tanks	ASME Code, Section VIII
Condensate phase separators	American Petroleum Institute No. 650
Cleanup phase separators	ASME Code, Section VIII
Waste sludge phase separators	ASME Code, Section III, Class 3

TABLE 9.2-2 (SHEET 1 OF 4)

CAPACITY AND MAXIMUM ACTIVITY CONTAINED IN LIQUID RADWASTE TANKS

	Waste Collector Tank	Floor Drain Collector Tank	Chemical Waste Tank	Laundry Drain Tank	Chem Waste/ Floor Drain Neutralizer Tank	Waste Sample Tank	Floor Drain Sample Tank	Demineralizer Feed Tank
No. of Tanks	1	1	1	2	1	2	1	1
Volume of each tank (gal)[b]	12,000	12,000	4500	1000	15,000	12,000	12,000	12,000
Isotopic concentration (μCi/cc)[d]								
Br-83	1.3E-3	5.8E-5	1.3E-5		SAME AS CHEMICAL WASTE TANK	1.8E-6	8.1E-8	SAME AS FLOOR DRAIN COLLECTOR TANK
Br-84	2.3E-3	1.1E-4	2.3E-5			(c)	(c)	
Br-85	1.4E-3	6.3E-5	1.4E-5			0	0	
I-131[a]	1.2E-3	5.3E-5	1.2E-5			5.0E-5	2.3E-6	
I-132	1.1E-2	4.8E-4	1.1E-4			1.2E-5	5.6E-7	
I-133[a]	7.9E-3	3.6E-4	7.9E-5			2.3E-4	1.1E-6	
I-134	2.1E-2	9.3E-4	2.1E-4			6.5E-8	2.9E-9	
I-135[a]	1.2E-2	5.2E-4	1.2E-4			1.5E-4	6.7E-6	
Sr-89[a]	2.7E-4	1.2E-5	2.7E-6			1.2E-5	5.4E-7	
Sr-90[a]	2.1E-5	9.3E-7	2.1E-7			9.1E-7	4.1E-8	
Sr-91[a]	6.1E-3	2.7E-4	6.1E-5			1.1E-4	5.1E-6	
Sr-92	9.5E-3	4.3E-4	9.5E-5			1.9E-5	8.0E-7	
Zr-95	3.6E-6	1.6E-7	3.6E-8			1.6E-7	7.0E-9	
Zr-97	2.8E-6	1.3E-7	2.8E-8			7.5E-8	3.5E-9	
Nb-95	3.7E-6	1.7E-7	3.7E-8			1.6E-7	7.2E-9	
Mo-99[a]	2.0E-3	8.9E-5	2.0E-5			7.7E-5	3.5E-5	
Tc-99m	2.5E-2	1.1E-3	2.5E-4			2.7E-4	1.2E-5	
Tc-101	1.1E-2	5.1E-4	1.1E-4			(c)	(c)	
Ru-103	1.7E-6	7.8E-8	1.7E-8			7.5E-8	3.4E-9	
Ru-106	2.3E-7	1.0E-8	2.3E-9			1.0E-8	(c)	
Te-129	3.5E-6	1.6E-7	3.5E-8			1.5E-7	6.9E-9	
Te-134	4.3E-3	1.9E-5	4.3E-5			1.7E-4	7.7E-6	
Cs-134	1.4E-5	6.4E-7	1.4E-7	2.0E-6		6.3E-7	2.8E-8	
Cs-136	9.4E-6	4.2E-7	9.4E-8			4.1E-7	1.8E-8	
Cs-137[a]	2.1E-5	9.6E-7	2.1E-7	6.0E-6		9.5E-7	4.3E-8	
Cs-138	1.6E-2	7.1E-4	1.6E-4			(c)	(c)	
Ba-139	1.4E-2	6.2E-4	1.4E-4			1.5E-6	6.7E-8	
Ba-140[a]	7.9E-3	3.6E-5	7.9E-5			3.4E-5	1.5E-6	
Ba-141	1.5E-2	6.6E-4	1.5E-4			(c)	(c)	
Ba-142	1.4E-2	6.4E-4	1.4E-4			(c)	(c)	
Ce-141	3.5E-6	1.6E-7	1.5E-8			1.5E-7	6.9E-9	
Ce-143	3.1E-6	1.4E-7	3.1E-8			1.1E-7	4.8E-9	
Ce-144[a]	3.1E-6	1.4E-7	3.1E-8			1.4E-7	6.2E-9	
Pr-143	3.4E-6	1.5E-7	3.4E-8			1.4E-7	6.5E-9	
Nd-147	1.2E-6	5.6E-8	1.2E-8			5.3E-8	2.4E-9	
Np-239[a]	2.2E-2	9.7E-4	2.2E-4			8.2E-4	3.7E-5	
Na-24	1.3E-4	6.0E-6	1.3E-6		6.5E-7	3.4E-6	1.5E-7	3.0E-6

TABLE 9.2-2 (SHEET 2 OF 4)

	Waste Collector Tank	Floor Drain Collector Tank	Chemical Waste Tank	Laundry Drain Tank	Chem Waste/ Floor Drain Neutralizer Tank	Waste Sample Tank	Floor Drain Sample Tank	Demineralizer Feed Tank
Isotopic concentration (μCi/cc)[d] (continued)								
P-32[a]	1.3E-6	6.0E-8	1.3E-8		6.5E-9	5.7E-8	2.6E-9	3.0E-8
Cr-51	3.3E-5	1.5E-6	3.3E-7		1.7E-7	1.4E-6	6.5E-8	7.5E-7
Mn-54	2.7E-6	1.2E-7	2.7E-8		1.4E-8	1.2E-7	5.3E-9	6.0E-8
Mn-56	3.3E-3	1.5E-4	3.3E-5		1.7E-5	5.9E-6	2.6E-7	7.5E-5
Co-58[a]	3.3E-4	1.5E-5	3.3E-6	1.0E-6	1.7E-6	1.5E-5	6.6E-7	7.5E-6
Co-60[a]	3.3E-5	1.5E-6	3.3E-7	1.0E-6	1.7E-7	1.5E-6	6.6E-8	7.5E-7
Fe-59	5.3E-6	2.4E-7	5.3E-8		2.7E-8	2.3E-7	1.1E-9	1.2E-7
Ni-65	2.0E-4	9.0E-6	2.0E-6		1.0E-6	3.4E-7	1.5E-8	4.5E-6
Zn-65	6.7E-8	3.0E-9	(c)		(c)	2.9E-9	(c)	1.5E-9
Zn-69m	2.0E-6	9.0E-8	2.0E-8		1.0E-8	4.8E-8	2.2E-9	4.5E-8
Ag-110m[a]	4.0E-6	1.8E-7	4.0E-8		2.0E-8	1.8E-7	7.9E-9	9.0E-8
W-187	2.0E-4	9.0E-6	2.0E-6		1.0E-6	6.6E-6	3.0E-7	4.5E-6
Maximum activity concentration (@ 100,000 μCi/s, off-gas) (μCi/cc)	2E-1	9E-3	2E-3	1E-5	2E-3	2E-3	9E-5	9E-3
Total maximum activity in all full tanks (μCi)	9.1E+6	4.1E+5	3.4E+4	7.6E+1	1.1E+5	1.8E+5	4.1E+3	4.1E+5
Assumed type of liquid present in tank	Equipment drain (dilute reactor water)	Floor drain (dilute reactor water)	Lab drain (dilute reactor water)	Laundry drain	Filtered floor drain (dilute reactor water)	Processed equipment drain	Processed floor drain	Processed floor drain
Decay time applied (h)	0	0	0	0	0	12	12	0
Location	Radwaste bldg	Radwaste bldg	Radwaste bldg	Radwaste bldg	Radwaste add-on bldg	Radwaste bldg	Radwaste add-on bldg	Radwaste bldg

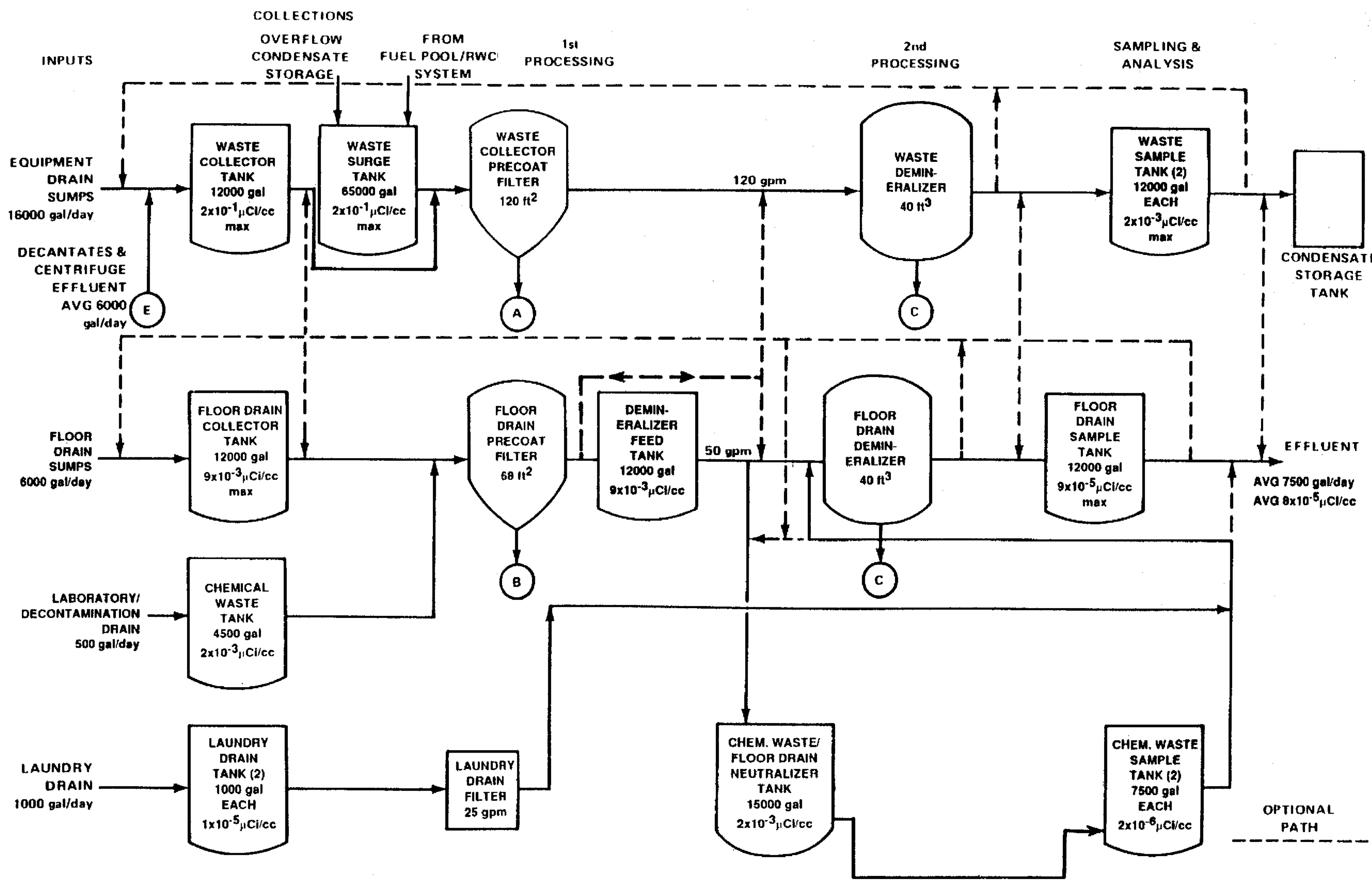
TABLE 9.2-2 (SHEET 3 OF 4)

	Chemical Waste Sample Tank	Condensate Backwash Receiving Tank	Condensate Phase Separator	Cleanup Phase Separator	Waste Sludge Tank	Spent-Resin Tank	Waste Surge Tank[b]
No. of Tanks	2	1	2	2	1	2	1
Volume of each tank (gal)[b]	7500	8500	13,500	4500	7500	600	65,000
Isotopic concentration (μCi/cc)[d]							
Br-83	1.8E-9	2.6E-6	SAME AS CONDENSATE BACKWASH RECEIVING TANK	4.5E-3	SAME AS CONDENSATE BACKWASH RECEIVING TANK	SAME AS CONDENSATE BACKWSH RECEIVING TANK	
Br-84	(c)	4.6E-6		8.1E-3			
Br-85	0	2.8E-6		4.9E-3			
I-131[a]	5.0E-8	2.4E-6		4.2E-3			
I-132	1.2E-8	2.1E-5		3.7E-2			
I-133[a]	2.3E-7	1.6E-5		2.8E-2			
I-134	(c)	4.2E-5		7.3E-2			
I-135[a]	1.5E-7	2.3E-5		4.1E-2			
Sr-89[a]	1.2E-8	5.4E-7		9.5E-4			
Sr-90[a]	(c)	4.1E-8		7.2E-5			
Sr-91[a]	1.1E-7	1.2E-5		2.1E-2			
Sr-92	1.9E-8	1.8E-5		3.3E-2			
Zr-95	(c)	7.1E-9		1.2E-5			
Zr-97	(c)	5.6E-9		9.9E-6			
Nb-95	(c)	7.4E-9		1.3E-6			
Mo-99[a]	7.7E-8	4.0E-6		6.9E-3			
Tc-99m	2.7E-7	4.9E-5		8.6E-2			
Tc-101	(c)	2.3E-5		4.0E-2			
Ru-103	(c)	3.4E-9		6.0E-6			
Ru-106	(c)	(c)		8.0E-7			
Te-129	(c)	7.0E-9		1.2E-5			
Te-134	1.7E-7	8.6E-6		1.5E-2			
Cs-134	(c)	2.8E-8		5.0E-5			
Cs-136	(c)	1.9E-8		3.3E-5			
Cs-137[a]	(c)	4.3E-8		7.5E-5			
Cs-138	(c)	3.2E-5		5.5E-2			
Ba-139	1.5E-9	2.7E-5		4.8E-2			
Ba-140[a]	3.4E-8	1.6E-6		2.8E-3			
Ba-141	(c)	3.0E-5		5.2E-2			
Ba-142	(c)	2.8E-5		5.0E-2			
Ce-141	(c)	7.0E-9		1.2E-5			
Ce-143	(c)	6.2E-9		1.1E-5			
Ce-144[a]	(c)	6.2E-9		1.1E-5			
Pr-143	(c)	6.7E-9		1.2E-5			
Nd-147	(c)	2.5E-9		4.4E-6			
Np-239[a]	8.2E-7	4.3E-5		7.5E-2			
Na-24	3.4E-9	2.7E-7		4.7E-4			
P-32[a]	(c)	2.7E-9		4.7E-6			
Cr-51	1.4E-9	6.7E-8		1.2E-4			

TABLE 9.2-2 (SHEET 4 OF 4)

	Chemical Waste Sample Tank	Condensate Backwash Receiving Tank	Condensate Phase Separator	Cleanup Phase Separator	Waste Sludge Tank	Spent-Resin Tank	Waste Surge Tank[b]
Isotopic concentration (μCi/cc)[d] (continued)							
Mn-54	(c)	5.3E-9	↓	9.3E-6	↓	↓	
Mn-56	5.9E-9	6.7E-6		1.2E-2			
Co-58[a]	1.5E-8	6.7E-7		1.2E-3			
Co-60[a]	1.5E-9	6.7E-8		1.2E-4			
Fe-59	(c)	1.1E-8		1.9E-5			
Ni-65	(c)	4.0E-7		7.0E-4			
Zn-65	(c)	(c)		2.3E-7			
Zn-69m	(c)	4.0E-9	↓	7.0E-6	↓	↓	
Ag-110m[a]	(c)	8.0E-9		1.4E-5			
W-187	6.4E-9	4.0E-7		7.0E-4			
Maximum concentration (@ 100,000 μCi/s, off-gas) (μCi/cc)	2E-6	4E-4	4E-4	7E-1	4E-4	4E-4	2.3E+6
Total maximum activity in all full tanks (μCi)	1.1E+2	1.3E+4	4.1E+4	2.4E+7	1.1E+4	1.1E+4	
Assumed type of liquid present in tank	Processed lab drain	Condensate	Condensate	Condensate + reactor water	Condensate	Condensate	
Decay time applied (h)	12	0	0	0	0	0	
Location	Radwaste add-on bldg	Turbine bldg	Radwaste bldg	Reactor bldg	Radwaste bldg	Radwaste bldg & add-on bldg	Radwaste bldg

a. Reference table 11.2-4 in HNP-2-FSAR.
b. Total liquid wastes in all tanks associated with radwaste system = 161, 700 gal. The waste surge tank is normally kept empty - not included in the total.
c. Less than 10^{-9}.
d. Total activities contained in all tanks at the maximum concentration in each tank = 34.3 Ci. Read 1.3E-3 as 1.3×10^{-3}.



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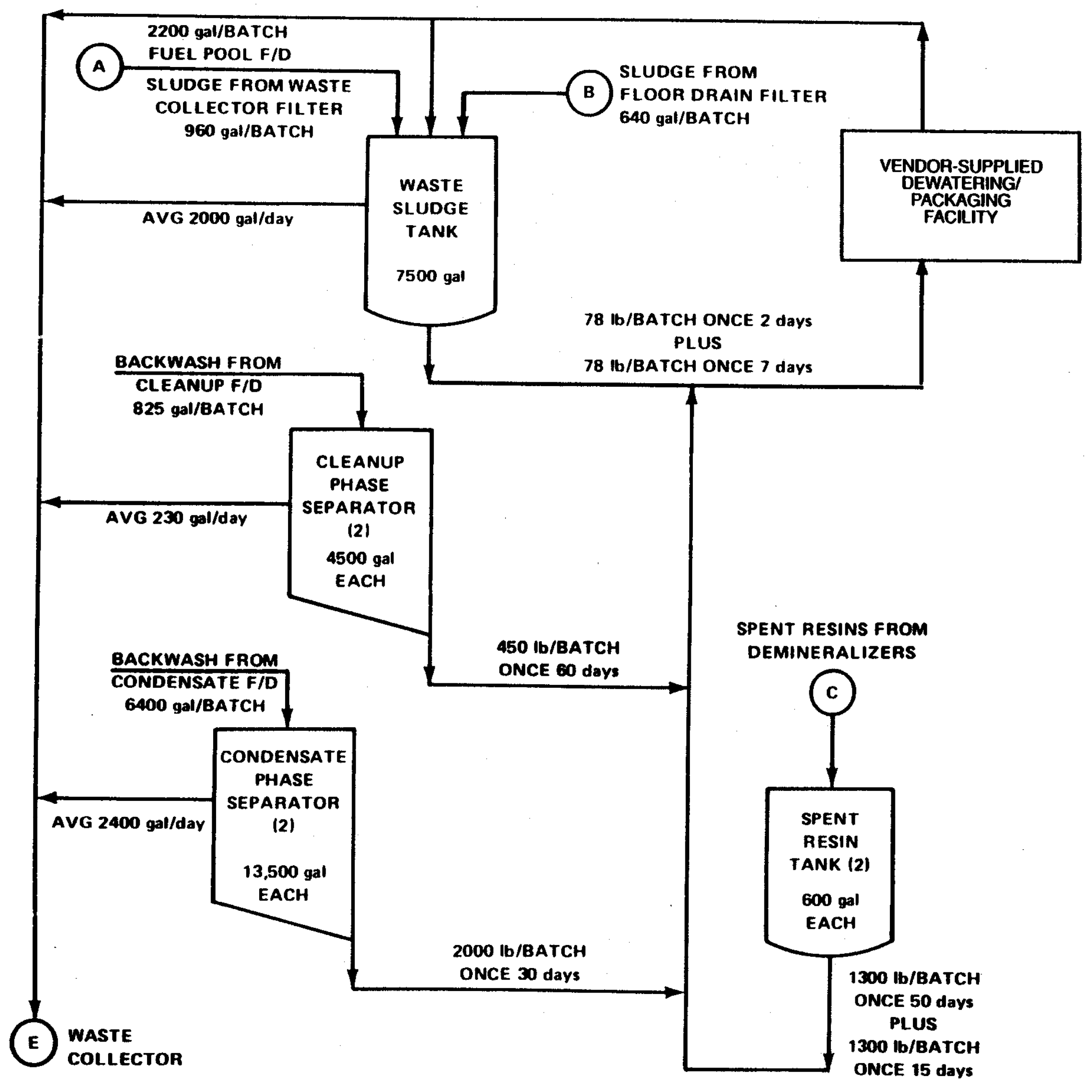
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

RADWASTE SYSTEM PROCESS DIAGRAM

FIGURE 9.2-1 (SHEET 1 OF 2)



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

RADWASTE SYSTEM PROCESS DIAGRAM

FIGURE 9.2-1 (SHEET 2 OF 2)

9.3 SOLID RADWASTE SYSTEM

9.3.1 POWER GENERATION OBJECTIVE

The solid radwaste system collects, monitors, processes, packages, and provides temporary storage facilities for radioactive solid wastes for offsite shipment and permanent disposal. The Edwin I. Hatch Nuclear Plant Solid Radioactive Waste Process Control Program (PCP) describes this objective. The PCP is implemented by procedures containing formulas, sampling, analyses, tests, and determinations to be made to ensure the processing and packaging of solid radioactive wastes, based on demonstrated processing of actual or simulated wet solid wastes, are accomplished to assure compliance with 10 CFR 20, 61, and 71, as well as State regulations and burial ground requirements governing the disposal of solid radioactive waste.

9.3.2 POWER GENERATION DESIGN BASES

A. The system is designed to provide collection services, processing, packaging, and storage of solid wastes resulting from normal plant operations, without limiting the operation or availability of the plant.

B. The system is designed to provide a reliable means for handling solid wastes and to allow system operation within permissible radiation exposure of plant personnel.

9.3.3 SAFETY DESIGN BASES

A. The solid radwaste system is designed to package radioactive solid wastes for offsite shipment and disposal or for storage at the onsite low-level radwaste (LLRW) storage facility in accordance with applicable regulations, including 49 CFR 170-178.

B. The solid radwaste system is designed to prevent the release of significant quantities of radioactive materials to the environment so as to keep the overall exposure to the public within the limits of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

9.3.4 DESCRIPTION

The solid radwaste system collects, processes, stores, and disposes of all solid radioactive waste.

9.3.4.1 Wet Waste

The wet solid radwaste system is a continuous part of the liquid radwaste system. Wet waste, consisting primarily of spent demineralizer resins and filter sludges, is accumulated in phase separators and waste sludge tanks. These tanks serve as storage and batching tanks for the wet solid radwaste system.

Wet solid waste is treated in one of the following methods:

A. Dewatered and packaged in high-integrity containers (HIC) if the packaged content has < 1% free water.

B. Dewatered and packaged in large shielded containers or HICs if the packaged content has < 0.5% free water and < 1.0 mCi/cc with a half-life ≥ 5 years.

C. Gross dewatered and packaged in stainless steel reusable liners for shipment to resin waste processors.

These containers meet the requirements of 49 CFR and are shipped in accordance with regulations of the Department of Transportation.

See HNP-2-FSAR paragraph 11.5.2.1 for discussion of wet solid waste inputs.

9.3.4.2 Dry Waste

Dry waste consists of air filters, miscellaneous paper, rags, etc., from contaminated areas; contaminated clothing, tools, equipment parts that cannot be effectively decontaminated; and solid laboratory wastes. The activity of much of this waste is low enough to permit handling by contact. This waste is collected in containers located in appropriate zones around the plant, as dictated by the volume of waste generated during operation and maintenance. The filled containers are secured and moved to a radiologically controlled area for temporary storage. Compressible waste is compacted to reduce their volume and placed into appropriate containers that meet the applicable transportation and disposal requirements. Offsite waste processors are also used to process, compact, and dispose of waste materials. Ventilation is provided to control contaminated particles while this packaging equipment is being operated. Noncompressible waste is packaged manually in similar containers. Because of its low activity, this waste can be stored until enough is accumulated to permit economical transportation to an offsite burial ground for final disposal or for storage at the onsite LLRW storage facility.

9.3.4.3 Irradiated Reactor Component

This waste consists primarily of spent control blades, fuel channels, incore ion chambers, and large pieces of equipment. Because of high activation and contamination levels, used reactor equipment is stored in the spent-fuel storage pool for sufficient radioactive decay before removal to inplant or offsite storage and final disposal in shielded containers or casks.

9.3.5 SAFETY EVALUATION

The safety evaluation applicable to HNP-2-FSAR paragraph 11.5.2.1 also applies to the HNP-1 wet solid radwaste system.

The safety evaluation for the waste separation and temporary storage facility is provided in HNP-2-FSAR subsection 11.5.6.

9.3.6 INSPECTION AND TESTING

The radwaste control systems are utilized on a routine basis and do not require specific testing to assure operability. The effectiveness of the design is measured by quantities of radioactivity released to the environment. Testing and calibration of the monitors are described in section 7.13.

9.4 GASEOUS RADWASTE SYSTEM

9.4.1 POWER GENERATION OBJECTIVE

The objective of the gaseous radwaste system is to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to individuals outside the controlled area is as low as reasonably achievable (ALARA) and does not exceed the design objectives in 10 CFR 50, Appendix I.

9.4.2 POWER GENERATION DESIGN BASES

The gaseous radwaste system is designed to limit offsite concentrations from routine station releases to significantly less than the limits specified in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) and to stay within the limits established in the plant operating license.

As a design basis for this system, a noble gas input equivalent to an annual average off-gas rate (based on 30-min decay) of 100,000 μCi/s diffusion mixture as shown in table 9.4-1 is used. A conservative value of 40 sf^3/min for condenser air in-leakage is used as a design basis.

Furthermore, during normal operation the gaseous radwaste system is designed to process and control the release of radioactive effluents to the site environs so as to maintain ALARA the exposure to persons in unrestricted areas to comply with Appendix I to 10 CFR 50.

9.4.3 SAFETY DESIGN BASES

The safety design basis for off-gas processing is to hold the gas until a sufficient fraction of the radionuclides has decayed. Radioactive particulate daughters are retained by the charcoal and the high-efficiency particulate air (HEPA) filters.

9.4.4 RADIOACTIVE GAS SOURCES

There are five potential sources of radioactive gas in this boiling water reactor (BWR) plant, as described below.

9.4.4.1 Process Off-Gas

Noncondensible radioactive off-gas is continuously removed from the main condenser by the air ejector during plant operation. This is the major source and is larger than all other sources combined. The air ejector off-gas normally contains activation gases, principally N-16, 0-19, and N-13. The N-16 and 0-19 have short half-lives and are readily decayed. The 10-min N-13 is present in small amounts that are further reduced by decay. The air ejector off-gas also contains the radioactive noble gas parents of biologically significant Sr-89, Sr-90, Ba-140, and

Cs-137. The concentration of these noble gases depends on the amount of tramp uranium in the coolant and on the cladding surfaces (usually extremely small) and the number and size of fuel cladding leaks.

Decay of the isotopes having half-lives $<$ 1 min was estimated and deducted from the group totals. In general, the activity entering the main condenser was assumed to be composed of 50% of the activity shown in table 9.4-8. This material activity decayed for 6 s (3 s from vessel to turbine and 3 s in the turbine) and 20% of the same activity decayed for 28 s (3 s from vessel to turbine and 25 s in the turbine).

The activation products given in table 9.4-9 were calculated by accumulating the input as described above for the 0.5-s steam transit time through the main condenser, assuming no further decay. The values in table 9.4-9 are directly dependent upon the transit time assumed. Higher values of this transit time have commonly been used.

Radioactive particulate daughters are retained on the HEPA filters and on the charcoal. The off-gas is discharged to the environs via the main stack.

The activity of the process off-gas stream is monitored prior to treatment and as it exits the treatment system to preclude undetected high radiation releases. Periodically samples are taken to determine its isotopic gas composition.

The system is in use during normal power operation periods. Detailed maintenance procedures depend on a particular failure.

9.4.4.2 Mechanical Vacuum Pump Off-Gas

During startup of the plant and before operation of the steam jet air ejector (SJAE) is achieved, a mechanical vacuum pump is utilized for evacuation of the main turbine condenser. Past BWR experience has indicated that the mechanical vacuum pump will be run at various times throughout the year for a total release period of ~ 40 h/year (10 startups, 4 h each). During this time the meteorological conditions will be variable; therefore, average annual meteorology is assumed to exist during the various release periods. The primary noble gases shown to exist during operation of the mechanical vacuum pump are the xenon (Xe) 133 and 135 isotope daughters of iodine (I) 133 and 135. A release rate of 40,000 μCi/s of Xe-133 and 6000 μCi/s of Xe-135 is considered appropriate during operation of the mechanical vacuum pump. Consideration of a 1% carryover of iodine during normal operation with a partition factor in the condenser of 1000 and the respective liquid and air volumes in the condenser shows that negligible quantities of iodine, i.e., 4×10^{-12} mCi/s I-131, are released during this period of time. The effluent from the mechanical vacuum pump is routed to the plant stack for discharge to the environment via the gland-seal holdup line. The pump is isolated from the off-gas system whenever the main steam line monitor system indicates high radiation.

9.4.4.3 Drywell Ventilation

The drywell air is exposed to the neutron fluxes around the reactor vessel producing some activation products. Activity also can be introduced into the drywell atmosphere through venting of the primary system relief valves into the suppression chamber and as a result of release of activity from system leaks and drywell sumps. The drywell forms a closed system that can be purged with normal reactor building air, if necessary, when personnel access is required. The drywell also can be vented during plant startup to accommodate the expansion of air that occurs with increasing temperature or during plant operation if the oxygen content reaches specified limits. Air vented during startup and air purged during or after operation is discharged through the standby gas treatment system and its filters to remove airborne radioactivity.

9.4.4.4 Gland-Seal Condenser Off-Gas

During normal operation the gland-seal system off-gas, after condensation of bulk moisture, is held up for ~ 2 min for decay of short-lived activation gases before discharge into the main stack (section 11.4) where additional holdup is afforded by the stack design. Refer to table 9.4-1 for estimates of the radionuclide composition and release rates.

9.4.4.5 Turbine Building

The turbine building ventilation system is designed to minimize the potential for releasing airborne radioactivity from the turbine building to the environs. The system includes a chilled water system serving appropriately located area fan coil units to remove the majority of the heat load in the building. The balance of the system supplies outside air and exhausts the turbine building air in quantities consistent with established ventilation criteria for a building of the turbine building size.

The turbine building exhaust air flows in the building from low-radiation areas to high-radiation areas. This air is then ducted to filter banks and released via the reactor building vent plenum. The filter banks employ HEPA and charcoal filters to minimize particulate and halogen releases. Radiation monitors survey the bank performance with high-level annunciation in the main control room. These monitors are backed up by the reactor building vent plenum isokinetic probe.

The turbine building design exhaust air flowrate is 30,000 ft^3/min. The charcoal filters provided to minimize iodine releases are mounted in dual-tray module drawers. Each drawer contains ~ 45 lb of charcoal and has a nominal rating of 333 ft^3/min. Each tray is 24 in. by 26 1/2 in. by 2 in. deep. The drawers are separated by ~ 2 in.

The charcoal filters contain charcoal impregnated with TEDA with a minimum expected efficiency of 99%. This type of impregnant is used to increase charcoal efficiency at low concentrations; and because of its favorable weathering characteristics, it is suitable for a continuously operated system.

9.4.4.6 Radwaste Building and Addition

The radwaste building ventilation system has been designed to minimize the potential for releasing airborne radioactivity from the radwaste building to the environs. The ventilation system includes redundant supply fans, supply air filters, exhaust air filter trains, and redundant exhaust fans. The radwaste building addition has an identical ventilation system.

The supply air is ducted to the different areas of the radwaste building. The exhaust air is ducted to the filter trains and released via the reactor building vent plenum. The filter train consists of a bank of carbon adsorbers and a bank of HEPA filters to minimize particulate and halogen releases. Radiation monitors survey the bank performance with high-level annunciation in the main control room. These monitors are backed up by the reactor building vent plenum isokinetic probe.

The radwaste building design exhaust air flowrate is 18,000 ft^3/min (maximum). The charcoal filters are mounted in dual-tray module drawers. Each drawer contains ~ 45 lb of charcoal and has a nominal rating of 333 ft^3/min. Each tray is 24 in. by 26 1/2 in. by 2 in. deep. The drawers are separated by ~ 2 in.

The charcoal filters contain charcoal impregnated with TEDA with a minimum expected efficiency of 99%. This type of impregnant is used to obtain increased charcoal adsorption efficiency at low concentrations and because of its favorable weathering characteristics for a continuously operating system.

9.4.4.7 Other Potentially Radioactive Gases

Radioactive gas may be released from deliberate ventilation paths such as from the radiochemistry laboratory, reactor building, turbine building, and radwaste building. Iodine and particulate monitors are installed at the points of deliberate release of ventilation air which could have potentially significant amounts of radioactive material.

9.4.5 DESCRIPTION

9.4.5.1 Process Description

A process off-gas treatment system is incorporated in the plant design to reduce further the gaseous radwastes from the plant. The normal condenser off-gas system, shown on drawing no. H-16532, uses a high-temperature catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen from the air ejector system. After cooling (to ~ 130°F) to strip the condensibles and reduce the volume, the remaining noncondensibles (principally kryptons, xenons, and air) are delayed in the 30-min holdup system. The gas is cooled to 45°F and reheated to 74°F for humidity control before reaching the adsorption bed. The charcoal adsorption bed, operating in a constant-temperature vault, selectively adsorbs and delays the xenons and kryptons from the bulk carrier gas (principally air). This delay on the charcoal permits the xenon and krypton to decay in place. This system results in a reduction of the off-gas activity (Ci) released by a factor of ~ 15 relative to a 30-min holdup system and based on a diffusion mixture. Table 9.4-1 shows the estimated annual release rates from the charcoal adsorbers of various isotopes of krypton and xenon compared to a system releasing 100,000 μCi/s after a 30-min delay.

The adsorption of noble gases on charcoal depends on gas flowrate, mass of charcoal, and gas-unique coefficients known as the dynamic adsorption coefficients. The parametric interrelationships and governing equations are well proved from 3 years of operation of a similar unit at Kernkraftwerk FWE Bayermwerk (KRB) BWR in Germany. The selection of the dynamic adsorption coefficients is based on information submitted in Bailly (Docket No. 50-367).

9.4.5.2 <u>Equipment Description</u>

The description of the major equipment is given in table 9.4-2.

9.4.5.3 <u>Instrumentation and Control</u>

The radiation levels at the air ejector off-gas discharge line and after the off-gas treatment system are continuously monitored by pairs of detectors. This system is also monitored by flow, temperature, and humidity instrumentation and hydrogen analyzers to ensure correct operation and control and to ensure that hydrogen concentration is maintained below the flammable limit. Process radiation instrumentation is described in section 7.12. Table 9.4-3 lists process instruments that cause alarms and whether they are indicated or recorded in the control room.

9.4.6 SAFETY EVALUATION

The decay time provided by the 30-min holdup pipe and the long delay charcoal adsorbers is established to provide for major radioactive decay of the activation gases and fission gases in the main condenser off-gas. The adsorbers provided an estimated 6.8-day xenon and 9.0-h krypton holdup. The daughter products that are solids are removed by filtration following the 30-min holdup and/or are retained on the charcoal. Final filtration of the charcoal adsorber effluent precludes escape of charcoal fines that would contain radioactive materials. Particulate activity release is thus negligible.

Although iodine input into the off-gas system is small by virtue of its retention in reactor water and condensate, the charcoal effectively removes it by adsorption.

A radiation monitor at the recombiner outlet continuously monitors radioactivity release from the reactor and, therefore, continuously monitors the degree of fuel leakage and input to the charcoal adsorbers. This radiation monitor is used to provide an alarm on high radiation in the off-gas. A radiation monitor is also provided at the outlet of the charcoal adsorbers to continuously monitor the release rate from the adsorber beds. This radiation monitor is used to isolate the off-gas system on high radioactivity to prevent treated gas of unacceptably high activity from entering the main stack. The stack radiation monitor is described in section 7.12.

Shielding is provided for off-gas system equipment to maintain safe radiation exposure levels for plant personnel. The equipment is principally operated from the control room.

The charcoal adsorbers operate at essentially room temperature so that, on system shutdown, radioactive gases in the adsorbers are subject to the same holdup time as during normal operation, even in the presence of continued air flow. The charcoal adsorbers are designed to limit the temperature of the charcoal to well below the charcoal ignition temperature, thus precluding overheating or fire and consequent escape of radioactive material. The adsorbers are located in a shielded room and maintained at a constant temperature by an air-conditioning system that removes the decay heat generated in the absorbers. Failure of the air-conditioning system causes an alarm in the control room. In addition, a radiation monitor is provided to monitor the radiation level in the charcoal bed vault. High radiation causes an alarm in the control room.

The hydrogen concentration of gases from the air ejector is kept below the flammable limit by maintaining adequate reactor steam flow for dilution at all times. This steam flowrate is monitored and alarmed. Both preheater trains are heated by electric band heaters. The recombiner temperatures are monitored and alarmed to indicate any deterioration of performance. A hydrogen analyzer downstream of the off-gas condenser performs an additional check.

The gaseous radwaste system piping and equipment are designed to be explosion resistant by employing design methods for circular-section steel systems to contain explosions of near stoichiometric mixtures of gaseous hydrogen and oxygen.

The design method uses a static analysis with dynamic materials properties. More exact rigorous dynamic analyses were conducted on selected designs with the results confirming that the static method is sufficiently conservative to use for off-gas system design. Ratios of maximum pressure to initial pressure (prior to an explosion) varying from 17 to 170 are used to determine the maximum peak pressure in the component under analysis. Wall thicknesses for the particular component are then computed using the maximum peak pressure as the pressure load. This analysis is covered in a proprietary report submitted to the Nuclear Regulatory Commission.(1)

An equivalent detonation-containing-static-pressure is then derived for which the component can be "rated," based upon the wall thickness calculated per the above procedure. (2)

The off-gas filters in the stack are the afterfilters. These afterfilters have a low radioactive inventory and would not have a significant effect on offsite dose if they were ruptured. Heat generated by radioactive decay, upon rupture, is insignificant based upon the following data:

> For the earlier 30-min holdup (prerecombiner charcoal) system the maximum activity buildup was 900 Ci. Allowing for a conversion factor of 40 Ci/W, the heat available is about 22.5 W. This heat is dispersed over 200 ft^2 of filter area and is, therefore, negligible. Furthermore, the effect of the recombiner charcoal (RECHAR) system is to reduce the activity and thermal values by a factor of 10^4.

The main process stream of the offgas system was originally designed and fabricated to American Society of Mechanical Engineers (ASME) Code, Section III, Nuclear Power Plant Components, Class 3, 1971 Edition plus Addenda. The safety classification has been reclassified to meet the intent of Quality Group D of Regulatory Guide 1.26. Auxiliary equipment components are designed to ASME Code, Section VIII, Division 1 requirements or to the requirements of ANSI B31.1.0 or American Petroleum Institute (API)-650, as appropriate.

The air ejector off-gas system operates at a pressure of ≤ 6 psig so the differential pressure that could cause leakage is small.

To limit possible sources of leakage of radioactive gases the system is welded wherever possible and bellows seal valve stems or equivalent are used.

Operational control is maintained by the use of radiation monitors to keep the release rate within the established limits. Environmental monitoring is used. However, at the estimated low dose levels, it is doubtful that the measurements can distinguish doses from the plant from normal variations in background radiation. Provision is made for sampling and periodic analysis of the influent and effluent gases for purposes of determining their compositions. This information is used in calibrating the monitors and in relating the release to calculated environs dose. The operator is thus in control of the system at all times.

Table 9.4-4 contains a detailed malfunction analysis indicating consequences and design precautions taken to accommodate failure of various components of the system.

9.4.6.1 Steam Jet Air Ejector Process Gas RECHAR System Activity Inventory and Failure Dose Consequences

Table 9.4-5 is a list of the isotopic inventories of the equipment in the RECHAR system. This analysis was based upon the diffusion mixture source terms, holdup times calculated for the equipment, removal and holdup mechanism postulated, and the inventories which were machine calculated.

The bases for calculations are:

- 40 sf^3/min air inleakage.
- 100,000 μCi/s noble gas diffusion mixture after 30-min delay.
- 12 charcoal beds - 37 tons of charcoal.
- Retention of daughter products by equipment.
  - Off-gas condenser - 100% but washed out.
  - Water separator - 100% but washed out.

- Holdup pipe - 60% but washed out.

- Carbon beds - 100%.

- Post-filter - 100%.

The assumptions generally give conservative daughter inventories or do not have a significant effect on daughter inventories.

At Dresden 2, iodine activities were measured in the reactor water, condensate pump discharge, and off-gas after being discharged from the 30-min holdup pipe. An iodine reduction factor from the condensate (primary steam) to discharge of the holdup pipe was calculated. The following basis was used to calculate the iodine inventories shown in table 9.4-5:

- Standard plant iodine source terms at 100,000 μCi/s noble gas at 30-min decay for the reactor water.

- Steam separation of 2% (reduction of a factor of 50 for iodine from the reactor water to the steam).

- Iodine reduction factor from primary steam to discharge of the holdup pipe as measured at Dresden 2.

The iodine inventories of table 9.4-5 are based upon use of a 30-min holdup with a RECHAR system. The RECHAR system has a comparable system but also several other features that are expected to materially reduce iodine reaching the charcoal, e.g., the precious metal recombiner and a 49°F dewpoint of the gas steam versus ~ 120°F dewpoint of a 30-min holdup system.

Equipment and piping are designed to contain an explosion so that this is not considered as a failure mode. The following equipment failures are postulated:

The charcoal adsorber vessels are 4 ft in diameter by 21-ft tall, dished heads, and 350-psig design pressure with a charcoal depth of ~ 19 ft. The gas flow is distributed internally by means of a distributor ring in the inlet and outlet of the vessel. The charcoal is granular activated charcoal in the range of 8 to 16 mesh (U.S. Seive). The vault is not accessible during operation because of the activity level; therefore, no failure due to an operator accident is considered.

The vault temperature and the charcoal vessel temperature are controlled at or near 77°F. The maximum mid-line temperature in the charcoal vessel rises < 10°F if flow stops. Decay heat load of the charcoal beds is 32 Btu/h at the design basis of 100,000 µCi/s.

The only credible failure to these vessels that could result in loss of carbon from the vessels would be failure of the concrete structure surrounding the vessel. A circumferential failure could result from concrete falling on the vessel under one of two conditions:

- Bending load - The vessel being supported in the center and loaded on each end. This could possibly result in a tear around 50% of the circumference.

- Shearing load - The vessel being supported and loaded near the same point from above.

In either case, not more than 10 to 15% of the carbon is displaced from the vessel. Iodine is strongly bonded to the charcoal and not expected to be removed by exposure to the air. One-percent loss of iodine is a conservative estimate.

Measurements made at KRB indicate that off-gas is ~ 30% richer in krypton than air. Therefore, if this carbon is exposed to air, it will eventually obtain equilibrium with the noble gases in the air. However, the first few inches of carbon will blanket the underlying carbon from the air. A 10% loss of noble gas from a failed vessel is conservative because of the small fraction of carbon exposed to the air.

<u>Holdup pipe</u> - Pipe rupture and depressurization of the pipe is considered. The pipe operates at 17.7 psia and depressurizes to 14.7 psia or ~ 20%. The model used did not assume any plateout or washout in calculating the holdup pipe inventory so that the estimated aerosols discharged are high by perhaps a factor of 10.

Table 9.4-5 gives the total and component radioactive inventories for the RECHAR system. Table 9.4-4 presents a detailed analysis of possible equipment malfunctions and also indicates the design precautions which have been taken to prevent radioactive releases to the environment.

Onsite and offsite doses resulting from failure of components of the RECHAR system are given in table 9.4-7 which was based on the following parametric values:

Release height	0
Wind speed	1 m/s
Atmospheric stability	Very stable
Breathing rate	347 cc/s

Table 9.4-6 indicates the fractional releases of component activity used in the component failure dose calculations.

Note that the particulate doses presented in table 9.4-7 are based on a correlation between the maximum permissible concentration air and dose received. The above approach results in maximizing the dose effects.

9.4.6.2 <u>Normal Radioactive Releases</u>

9.4.6.2.1 Estimate of Expected Releases

Estimates of the annual releases of radioactive gaseous effluents during normal plant operation, including anticipated operational occurrences, were calculated using the BWR-GALE Code. HNP-2-FSAR subsection 11.3.4 discusses the methodology and data used in obtaining estimated isotopic gaseous and particulate releases from Plant Hatch. HNP-2-FSAR table 11.3-6 lists the input data used in the BWR-GALE Code and provides the resulting annual gaseous and particulate releases calculated by the BWR-GALE Code.

9.4.6.2.2 Release Points

Gaseous effluents may be released from three points during normal operation. These three points are the HNP-1 reactor building vent plenum, the main stack, and the off-gas recombiner building. Each of these release pathways has gaseous effluent radiation monitors. The radiological environmental monitoring program is described in detail in the Offsite Dose Calculation Manual (ODCM).

For estimating expected releases using the BWR-GALE code, two release points are modeled, the reactor building vent plenum which is considered a ground level release and the main stack which is considered an elevated release. The off-gas recombiner building release pathway is implicitly considered part of the ground level release in the estimate of expected releases discussed in HNP-2-FSAR paragraph 11.3.4.1. The atmospheric diffusion conditions assumed for each release point are discussed in detail in HNP-2-FSAR paragraph 2.3.5.2.3.2.

9.4.6.2.3 Dilution Factors

The long-term (annual average) atmospheric dispersion factors (X/Q) and deposition factors (D/Q) out to a distance of 50 miles were estimated based on 4 years of onsite meteorological data. The methodology used for the meteorological diffusion calculations is discussed in detail in subsection 2.3.5 of the HNP-2-FSAR. Furthermore, the same methodology was used to calculate the X/Qs and D/Qs at the nearest site boundary, residence, vegetable garden, milk cow, and meat animal for each of 16 radial sectors, out to 8000 m. These data are presented in HNP-2-FSAR tables 2.3-22 and 2.3.23 for elevated releases (main stack) and ground level releases (reactor building vent), respectively.

9.4.6.2.4 Estimated Doses

HNP-2-FSAR subsection 11.3.4 describes the dose calculation methodology used and the resulting data, and also discusses compliance with the design objectives outlined in 10 CFR 50, Appendix I. HNP-2-FSAR table 11.3-7 provides estimated maximum individual doses based on the releases listed in HNP-2-FSAR table 11.3-6.

9.4.6.3 Accident Analysis

Refer to HNP-2-FSAR subsection 15.4.15 for the accident analysis of failure of the off-gas system, failure of the SJAE line, and malfunction of the turbine gland-sealing system.

9.4.7 INSPECTION AND TESTING

The gaseous waste disposal systems are used on a routine basis and do not require specific testing to assure operability. Monitoring equipment is calibrated and maintained on a specific schedule and on indication of malfunction.

The particulate filters are tested using a dioctyl phthalate (DOP) smoke test or equivalent.

Calibration of the off-gas and stack effluent monitors is performed in accordance with plant procedures.

REFERENCES

1. Nesbitt, L. B., "Pressure Integrity Design Basis for New Gas Systems," NEDE-11146, Proprietary, July 1971.

2. Nesbitt, L. B., "OffGas System Piping Evaluation," GE-NE-N62-00024-00-01, Rev. 0, September 2000.

TABLE 9.4-1

ESTIMATED PROCESS OFF-GAS RELEASE RATES FROM MAIN CONDENSER[(a)]

Isotope	Activity After 30-min Delay (μCi/s)	Discharge Rate from Charcoal Adsorbers (μCi/s)	Annual Discharge from Charcoal Adsorbers[(b)] (Ci/year)	Inventory at End of 1 year due to 1 year of Operation (Ci)
Kr-83m	2,850	50	1,580	1
Kr-85m	5,050	934	29,500	21
Kr-85	8	8	254	246
Kr-87	14,800	40	1,250	1
Kr-88	16,200	1,140	35,900	17
Kr-89	264	-	-	-
Xe-131m	11	6	194	9
Xe-133m	200	24	762	7
Xe-133	5,210	2,180	68,700	1,430
Xe-135m	8,070	-	-	-
Xe-135	17,700	-	2	-
Xe-137	1,010	-	-	-
Xe-138	28,700	-	-	-
Halides	Negligible	Negligible	Negligible	Negligible
TOTAL	100,000	4,400	138,000	1,730

a. Release rates are given in μCi/s, based on a diffusion mixture.
b. At 100% plant capacity factor.

TABLE 9.4-2 (SHEET 1 OF 2)

OFF-GAS SYSTEM MAJOR EQUIPMENT ITEMS

Off-Gas Preheaters - Two required

Construction of Electric Band Heater Train: Band heaters are installed on the exterior of the off-gas piping with 4 heater zones per train, each zone containing 9 heaters, for a total of 36 heaters per train. The band heater is constructed of a nickel-chrome helical heating coil mounted with ceramic supports and enclosed in a fluted stainless-steel sheath. Alpha preheater train has an insulation shroud constructed of fluted stainless-steel wrapped around its heaters, while the bravo preheater train has thermal insulation wrapped around its heaters.

Catalytic Recombiners - Two required

Construction: Stainless-steel cartridge, low-alloy steel shell; catalyst cartridge containing a precious metal catalyst on nichrome strips or porous, nondusting ceramic; catalyst cartridge to be replaceable without removing vessel; 350-psig design pressure; 900°F design temperature.

Off-Gas Condenser - One required

Construction: Stainless-steel or low-alloy shell; stainless-steel tubes; 350-psig shell design pressure; 250-psig tube design pressure; 900°F design temperature.

Water Separator - One required

Construction: Carbon-steel shell; stainless-steel wire mesh; 350-psig design pressure; 250°F design temperature.

30-min Holdup Piping

Construction: Carbon steel (buried) with the outside wrapped and coated for corrosion protection; 150°F temperature; radiography of all longitudinal welds and each end weld of the 43-in. elbow.

Cooler-Condenser - Two required

Construction: Stainless-steel shell; stainless-steel tubes; 100-psig tube design pressure; 350-psig shell design pressure; 50°F tube design temperature; 150°F shell design temperature.

TABLE 9.4-2 (SHEET 2 OF 2)

Moisture Separators (Downstream of Cooler-Condenser) - Two required

Construction: Carbon-steel shell; stainless-steel wire mesh; 350-psig design pressure; 150°F design temperature.

Off-Gas Reheater - One required

Construction: Carbon-steel pipe; electrically heated.

Glycol Storage Tank - One required

Construction: Carbon steel; 3000 gal; water-filled hydrostatic design pressure; 0°F design temperature.

Glycol Solution Refrigerators and Motor Drives - Two required

Construction: Conventional refrigeration units; glycol exit solution temperature of 35°F.

Glycol Pumps and Motor Drives - Two required

Construction: Cast iron; 3-in. connections, 50 ft; 0°F design temperature.

Post-Filters - Two required

Construction: Carbon-steel shell; high-efficiency, moisture-resistant filter element; flanged shell; 350-psig design pressure; 130°F design temperature.

Carbon Bed Adsorbers - 12 beds

Construction: Carbon steel; 4-ft ID x 21-ft vessels, each with a 19-ft packed section containing ~ 3 tons of 8-14 mesh carbon (~ 200 ft^3 of charcoal) Columbia G or equivalent; 350-psig design pressure; 130°F design temperature.

TABLE 9.4-3 (SHEET 1 OF 2)

OFF-GAS SYSTEM PROCESS INSTRUMENT ANNUNCIATORS IN MAIN CONTROL ROOM[(a)]

Parameter	Indicator	Recorder
Recombiner inlet temperature - low	X	
Recombiner catalyst temperature - high/low		X
Off-gas condenser water (dual) level - high/low		
Off-gas condenser gas outlet temperature - high		
H_2 analyzer (condenser discharge) - (dual) - high		X
Pre-treatment off-gas condenser discharge radiation - high		X
Gas flow (carbon bed discharge) - high/low		X
Gas reheater inlet temperature - high/low		X
Glycol storage tank temperature - high/low		X
Glycol tank level - low		
Gas reheater outlet dewpoint temperature - high		X
Adsorber vessel temperature - high		X
Adsorber vault temperature - high/low		X
Adsorber inlet/outlet pressure - high	X	
Post-treatment off-gas radiation - high		X
Refrigeration machine inoperable		
Carbon bed vault radiation - high	X	
Prefilter differential pressure - high	X	

a. All listed parameters provide input to MCR annunciators, and selected parameters are provided with indicators or recorders as shown.

TABLE 9.4-3 (SHEET 2 OF 2)

Parameter	Indicator	Recorder
Off-gas carbon bed (control switch) - bypassed		
Afterfilters differential pressure - high	X	
Third-stage SJAE steam flow A/B - high/low		
Standby stack dilution fan running		
Stack dilution fan trouble		
Instrumentation Elements		
Temperature - thermocouple		
Level - differential pressure diaphragm		
Hydrogen - electrochemical galvonic sensor		
Gas flow - thermal mass flow element		
Differential pressure - differential pressure diaphragm		
Humidity - moisture element		
Radiation - sample chambers and detectors		

TABLE 9.4-4 (SHEET 1 OF 3)

EQUIPMENT MALFUNCTION ANALYSIS

Equipment Item	Malfunction	Consequence	Design Precautions
Electric Band Preheaters	Out of service band heater zone	Without additional heating, off-gas inlet temperature to recombiner would decrease, which would cause condensate to form in the pipeline and improper dilution of the off-gas.	Other zones will maintain design off-gas temperature to recombiner.
	Temperature control failure	Off-gas stream and pipeline will overheat.	No single failure of controls can result in heating of the piping to the auto ignition temperature of hydrogen.
Recombiners	Catalyst gradually deactivates	Temperature profile changes through catalyst. Eventually excess H_2 will be detected by H_2 analyzer or by gas flowmeter. Eventually the gas could become combustible.	Temperature probes in recombiner and H_2 analyzer provided. Spare recombiner.
	Catalyst gets wet at start	H_2 conversion falls off and H_2 is detected by downstream analyzers. Eventually the gas could become combustible.	Condensate drains, temperature probes in recombiner. Air bleed system at startup. Recombiner thermal blanket, spare recombiner, and heater. Hydrogen analyzer.
Recombiner condenser	Cooling water leak	The coolant (reactor condensate) will leak to the process gas (shell) side. This will be detected if drain well liquid level increases. Moderate leakage would be of no concern from a process standpoint. (The process condensate drains to the hotwell.)	None

TABLE 9.4-4 (SHEET 2 OF 3)

Equipment Item	Malfunction	Consequence	Design Precautions
Drain well	Liquid level instruments fail	If both drain valves fail to open, water will build up in the condenser and pressure drop will increase. The high ΔP, if not detected by instrumentation, can cause pressure buildup in the main condenser and eventually initiate a reactor scram. If a drain valve fails to close, gas will recycle to the main condenser, increase the load on the SJAE, and cause back pressure on the main condenser, eventually causing a reactor scram.	Two separate drain systems, each provided with high- and low-level alarms.
Water separator	Corrosion of wire mesh element	Higher quantity of water collects in 30-min holdup line and router to radwaste.	Stainless-steel mesh specified.
30-min holdup line	Corrosion of line	Leakage to soil of gaseous and liquid fission products.	Corrosion allowance = 0.250 in.
Cooler-condensers	Corrosion of finned tube	Glycol water solution will leak into process (shell) side and be discharged to clean radwaste. If not detected at radwaste, the glycol solution will discharge to the reactor condensate system.	Stainless-steel finned tubes specified. The inventory of glycol water can be observed in tank. A002 - spare cooler provided.
	Icing up of finned tube	Shell side of cooler can plug up with ice, gradually building up pressure drop. If this happens, the spare unit can be activated. Complete blockage of <u>both</u> units will increase ΔP and lead to a reactor scram.	Design glycol water solution temperature of 33°F to 38°F specified. Spare cooler - condenser provided. Redundant temperature indication provided. Common temperature alarmed.
Moisture separators	Corrosion of wire mesh element	Increased moisture will be retained in process gas routed to charcoal adsorbers. Over a long period, the charcoal performance will deteriorate as a result of moisture pickup.	Stainless-steel mesh specified. Relative humidity instrumentation provided. Spare unit provided.

TABLE 9.4-4 (SHEET 3 OF 3)

Equipment Item	Malfunction	Consequence	Design Precautions
Charcoal adsorbers	Charcoal gets wet	Charcoal performance will deteriorate gradually as charcoal gets wet. Holdup times for krypton and xenon will decrease, and plant emissions will increase.	Highly instrumented, mechanically simple gas dehumidification system with redundant equipment
Vault air-conditioning units	Mechanical failure	If ambient temperature exceeds ~ 80°F, increased emission could occur.	Spare air-conditioning unit provided.
		If ambient temperature is below ~ 60°F, charcoal could pick up additional moisture.	Vault temperature alarms provided.
Post filters	Hole in filter media	Probably of no real consequence. The charcoal media itself should be a good filter at the low air velocity.	ΔP instrumentation provided. Spare unit provided.
Glycol refrigeration machines	Mechanical failure	If spare unit fails to operate, the glycol solution temperature will rise, and the dehumidification system performance will deteriorate. This will cause gradual buildup of moisture on the charcoal, with increased plant emissions.	Spare refrigerator provided. Glycol solution temperature alarms provided.
SJAEs	Low flow of motive high-pressure steam	When the hydrogen and oxygen concentrations exceed 4- and 5-volume percent, respectively, the process gas becomes flammable.	Alarms for low-steam flow and low-steam pressure.
		Inadequate steam flow will cause overheating and deterioration of the catalyst.	Steam flow to be held at constant <u>maximum</u> flow regardless of plant power level.
	Wear of steam supply nozzle of ejector	Increased steam flow to recombiner. This could reduce degree of recombination at low-power levels.	

TABLE 9.4-5 (SHEET 1 OF 8)

INVENTORY ACTIVITIES - AMBIENT RECHAR (µCi)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser
Residence time	2.5-1 s	2.9-1 s	1.54+1 s	1.57 s	1.46+2 min	5.47+1 s
Operating time	0.	0.	0.	0.	0.	0.
Solid daughter capture	0.	0.	100%	100%	60%	0.
Solid daughter washout	-	-	100%	100%	100%	-
Isotope						
Kr-83M	8.675+2	1.006+3	5.339+4	5.438+3	1.909+7	7.664+4
Kr-85M	1.412+3	1.638+3	8.693+4	8.859+3	4.105+7	2.100+5
Kr-85	2.015	2.337	1.241+2	1.265+1	7.099+4	4.454+2
Kr-87	5.110+3	5.927+3	3.144+5	3.201+4	9.870+7	2.932+5
Rb-87	0.	0.	0.	0.	0.	0.
Kr-88	4.842+3	5.617+3	2.981+5	3.038+4	1.272+8	5.771+5
Rb-88	3.952-1	1.449	1.599+3	1.557+1	6.552+7	2.627+5
Kr-89	4.320+4	5.007+4	2.584+6	2.555+5	4.470+7	0.
Rb-89	4.105	1.504+1	1.629+4	1.525+2	2.677+7	1.182+3
Sr-89	0.	0.	1.377-2	1.262-5	3.037+4	1.541+2
Y-89M	0.	0.	2.123-3	0.	3.027+4	1.541+2
Kr-90	8.981+4	1.036+5	4.668+6	3.947+5	1.150+7	0.
Rb-90	4.807+1	1.757+2	1.710+5	1.331+3	6.900+6	9.
Sr-90	0.	0.	7.150-4	0.	4.446+1	1.912-1
Y-90	0.	0.	0.	0.	5.630-1	4.834-3
Kr-91	5.363+4	6.087+4	1.830+6	8.843+4	6.555+5	0.
Rb-91	8.064+1	2.922+2	2.094+5	8.452+2	3.933+5	0.
Sr-91	1.340-4	1.207-3	2.480+1	8.908-3	6.229+4	2.401+2
Y-91M	0.	0.	2.417-2	0.	3.594+4	2.202+2
Y-91	0.	0.	0.	0.	1.641+1	1.790-1
Kr-92	1.108+3	1.161+3	1.002+4	1.352+1	1.674+1	0.
Rb-92	2.153+1	7.394+1	1.048+4	1.662	1.005+1	0.
Sr-92	1.299-4	1.130-3	6.841	6.666-5	4.677+0	1.399-2

TABLE 9.4-5 (SHEET 2 OF 8)

Isotope	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser
Y-92	0.	0.	2.006-3	0.	1.048+0	7.222-3
Kr-93	3.839+1	3.853+1	2.286+2	3.336-2	2.521-2	0.
Rb-93	5.732-1	1.941	2.43+2	3.299-3	1.512-2	0.
Sr-93	7.456-5	6.427-4	3.387	2.882-6	1.512-2	0.
Y-93	0.	0.	3.475-4	0.	2.146-3	8.940-6
Zr-93	0.	0.	0.	0.	0.	0.
Nb-93M	0.	0.	0.	0.	0.	0.
Kr-94	1.085	1.045	4.694	7.215-5	3.665-5	0.
Rb-94	3.551-2	1.159-1	6.499	1.504-5	2.199-5	0.
Sr-94	2.700-5	2.272-4	6.221-1	0.	2.199-5	0.
Y-94	0.	0.	2.164-3	0.	2.183-5	0.
Kr-95	8.112-6	6.476-6	1.304-5	0.	0.	0.
Rb-95	1.766-6	4.329-6	2.154-5	0.	0.	0.
Sr-95	0.	0.	8.933-6	0.	0.	0.
Y-95	0.	0.	0.	0.	0.	0.
Zr-95	0.	0.	0.	0.	0.	0.
Nb-95	0.	0.	0.	0.	0.	0.
Kr-97	6.512-4	6.268-4	2.816-3	0.	0.	0.
Rb-97	2.841-4	5.815-4	3.228-3	0.	0.	0.
Sr-97	4.077-5	2.184-4	3.834-3	0.	0.	0.
Y-97	1.680-6	2.256-5	4.067-3	0.	0.	0.
Zr-97	0.	0.	0.	0.	0.	0.
Nb-97M	0.	0.	0.	0.	0.	0.
Nb-97	0.	0.	0.	0.	0.	0.
Xe-131M	2.286	2.652	1.408+2	1.436+1	7.988+4	4.973+2
Xe-133M	4.950+1	5.742+1	3.049+3	3.108+2	1.708+6	1.050+4
Xe-133	1.354+3	1.571+3	8.342+4	8.504+3	4.715+7	2.925+5
Xe-135M	7.937+3	9.205+3	4.860+5	4.924+4	4.252+7	2.663+3

Isotope

TABLE 9.4-5 (SHEET 3 OF 8)

	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser
Xe-135	4.740+3	5.498+3	2.920+5	2.977+4	1.579+8	9.043+5
Cs-135	0.	0.	0.	0.	4.063-3	3.322-5
Xe-137	5.195+4	6.022+4	3.123+6	3.103+5	6.529+7	3.222-5
Cs-137	4.722-6	1.730-5	1.887-2	1.772-4	2.401+2	1.039
Ba-137M	0.	0.	4.485-4	4.196-7	2.338+2	1.039
Xe-138	2.732+4	3.169+4	1.672+6	1.693+5	1.324+8	4.654+3
Cs-138	1.226	4.494+0	4.948+3	4.771+1	7.344+7	7.808+4
Xe-139	9.213+4	1.064+5	4.946+6	4.341+5	1.577+7	0.
Cs-139	1.429+1	5.226+1	5.275+4	4.242+2	9.461+6	8.539
Ba-139	1.656-4	1.501-3	3.994+1	3.093-2	6.282+6	1.605+4
Xe-140	7.084+4	8.109+4	3.002+6	1.973+5	2.467+6	0.
Cs-140	9.663+1	3.516+2	2.907+5	1.700+3	1.480+6	0.
Ba-140	5.055-6	4.567-5	1.046	5.622-4	8.005+3	3.366+1
La-140	0.	0.	2.089-5	0.	1.637+2	1.374
Xe-141	5.719+2	5.951+2	4.791+3	4.540	5.143	0.
Cs-141	2.038	7.091	1.860+3	1.089-1	3.086	0.
Ba-141	1.081-4	9.485-4	8.687	3.793-5	3.073	2.843-4
La-141	0.	0.	2.105-3	0.	9.154-1	3.906-3
Ce-141	0.	0.	0.	0.	8.944-4	8.264-6
Xe-142	1.888+1	1.879+1	1.049+2	9.839-3	6.836-3	0.
Cs-142	9.548-1	3.105	1.378+2	2.915-3	4.101-3	0.
Ba-142	8.768-5	7.367-4	1.796	1.867-6	4.101-3	0.
La-142	0.	0.	1.405-3	0.	2.549-3	7.051-6
Xe-143	3.806-1	3.635-1	1.561	1.569-5	7.450-6	0.
Cs-143	1.932-2	6.170-2	2.216	4.779-6	4.470-6	0.
Ba-143	9.493-5	7.845-4	1.143	0.	4.470-6	0.
La-143	0.	0.	6.671-3	0.	4.467-6	0.
Ce-143	0.	0.	0.	0.	0.	0.
Pr-143	0.	0.	0.	0.	0.	0.
Xe-144	9.575+1	1.088+2	3.346+3	1.676+2	1.304+3	0.

TABLE 9.4-5 (SHEET 4 OF 8)

Isotope	Preheater	Recombiner	Off-Gas Condenser	Water Separator	Holdup Pipe	Cooler Condenser
Cs-144	7.182+0	2.418+1	3.314+3	6.221+1	7.825+2	0.
Ba-144	3.521-2	3.010-1	1.250+3	2.015	7.825+2	0.
La-144	3.752-5	7.437-4	1.129+2	1.406-2	7.825+2	0.
Ce-144	0.	0.	1.308-5	0.	1.913-1	8.045-4
Pr-144	0.	0.	0.	0.	1.583-1	8.021-4
Halogens	-	-	-	-	-	-
N-13	2.104+3	2.440+3	1.284+5	1.296+4	7.173+6	1.844+1
N-16	1.513+7	1.710+7	4.643+8	1.895+7	1.149+8	0.
N-17	1.448+3	1.606+3	2.986+4	5.683+2	1.893+3	0.
0-19	2.240+5	2.581+5	1.126+7	9.161+5	2.212+7	0.
TOTAL	1.581+7	1.789+7	5.000+8	2.190+7	9.995+8	2.731+6
Gas Kr + Xe	4.570+5	5.263+5	2.345+7	2.014+6	8.091+8	2.372+6
Solid daughters	0.003+5	0.010+5	0.078+7	0.005+6	1.904+8	3.587+5
Kr gas	2.000+5	2.299+5	9.845+6	8.153+5	3.439+8	1.157+6
Xe gas	2.570+5	2.964+5	1.361+7	1.199+6	4.653+8	1.215+6

TABLE 9.4-5 (SHEET 5 OF 8)

	Moisture Separator	Reheater	Charcoal Vessel Train	First Charcoal Vessel	Afterfilter
Residence time	2.00 s	4.46 s	Kr-8.98 h Xe-6.76 day	Kr-0.75 h Xe-0.56 day	1.34+1 s
Operating time	0.	0.	10 years	10 years	1 year
Solid daughter capture	0.	0.	100%	100%	100%
Solid daughter washout	-	-	0%	0%	0%
Isotope					
Kr-83M	2.794+3	6.229+3	1.307+7	3.294+6	6.683+2
Kr-85M	7.670+3	1.710+4	6.631+7	9.772+6	1.246+4
Kr-85	1.629+1	3.632+1	2.661+5	2.204+4	1.109+2
Kr-87	1.068+4	2.380+4	3.483+7	1.182+7	5.231+2
Rb-87	0.	0.	5.359-3	2.177-3	0.
Kr-88	2.106+4	4.695+4	1.361+8	2.595+7	1.513+4
Rb-88	9.817+3	2.194+4	1.437+8	3.350+7	1.513+4
Kr-89	0.	0.	0.	0.	0.
Rb-89	4.231+1	9.413+1	2.772+4	2.772+4	0.
Sr-89	5.634	1.256+1	1.773+7	1.773+7	0.
Y-89M	5.634	1.256+1	1.774+7	1.774+7	0.
Kr-90	0.	0.	0.	0.	0.
Rb-90	0.	0.	0.	0.	0.
Sr-90	6.990-3	1.559-2	1.088+5	1.088+5	0.
Y-90	1.773-4	3.955-4			0.
Kr-91	0.	0.	0.	0.	0.
Rb-91	0.	0.	0.	0.	0.
Sr-91	8.774	1.956+1	2.204+5	2.204+5	0.
Y-91M	8.057	1.797+1	2.380+5	2.380+5	0.
Y-91	6.574-3	1.467-1	2.586+5	2.586+5	0.
Kr-92	0.	0.	0.	0.	0.
Rb-92	0.	0.	0.	0.	0.
Sr-92	5.150-4	1.138-3	3.564	3.564	0.

TABLE 9.4-5 (SHEET 6 OF 8)

Isotope	Moisture Separator	Reheater	Charcoal Vessel Train	First Charcoal Vessel	Afterfilter
Y-92	2.644-4	5.898-4	5.990	5.990	0.
Kr-93	0.	0.	0.	0.	0.
Rb-93	0.	0.	0.	0.	0.
Sr-93	0.	0.	0.	0.	0.
Y-93	0.	0.	8.642-3	8.642-3	0.
Zr-93	0.	0.	0.	0.	0.
Nb-93M	0.	0.	0.	0.	0.
Kr-94	0.	0.	0.	0.	0.
Rb-94	0.	0.	0.	0.	0.
Sr-94	0.	0.	0.	0.	0.
Y-94	0.	0.	0.	0.	0.
Kr-95	0.	0.	0.	0.	0.
Rb-95	0.	0.	0.	0.	0.
Sr-95	0.	0.	0.	0.	0.
Y-95	0.	0.	0.	0.	0.
Zr-95	0.	0.	0.	0.	0.
Nb-95	0.	0.	0.	0.	0.
Kr-97	0.	0.	0.	0.	0.
Rb-97	0.	0.	0.	0.	0.
Sr-97	0.	0.	0.	0.	0.
Y-97	0.	0.	0.	0.	0.
Zr-97	0.	0.	0.	0.	0.
Nb-97M	0.	0.	0.	0.	0.
Nb-97	0.	0.	0.	0.	0.
Xe-131M	1.818+1	4.055+1	4.393+6	4.351+6	8.233+1
Xe-133M	3.838+2	8.558+2	4.725+7	8.574+6	3.233+2
Xe-133	1.069+4	2.385+4	2.090+9	2.510+8	3.004+4
Xe-135M	9.535+1	2.121+2	6.451+4	6.451+4	0.

TABLE 9.4-5 (SHEET 7 OF 8)

Isotope	Moisture Separator	Reheater	Charcoal Vessel Train	First Charcoal Vessel	Afterfilter
Xe-135	3.305+4	7.369+4	7.868+8	5.035+8	1.042
Cs-135	1.224-6	2.731-6	2.389+3	1.533+3	0.
Xe-137	1.080-6	2.386-6	1.759-4	1.759-4	0.
Cs-137	3.798-2	8.468-2	5.913+5	5.913+5	0.
Ba-137M	3.798-2	8.468-2	5.913+5	5.913+5	0.
Ba-141	1.021-5	2.272-5	8.062-3	8.062-3	0.
La-141	1.426-4	3.180-4	1.442	1.442	0.
Ce-141	0.	0.	2.056	2.056	0.
Xe-142	0.	0.	0.	0.	0.
Xe-138	1.663+2	3.698+2	1.018+5	1.018+5	0.
Cs-138	2.827+3	6.298+3	4.033+6	4.033+6	0.
Xe-139	0.	0.	0.	0.	0.
Cs-139	3.014-1	6.694-1	1.207+2	1.207+2	0.
Ba-139	5.845+2	1.303+3	2.101+6	2.101+6	0.
Xe-140	0.	0.	0.	0.	0.
Cs-140	0.	0.	0.	0.	0.
Ba-140	1.231	2.745	9.814+5	9.814+5	0.
La-140	5.039-2	1.124-1	9.867+5	9.867+5	0.
Xe-141	0.	0.	0.	0.	0.
Cs-141	0.	0.	0.	0.	0.
Ba-141	1.021-5	2.272-5	8.062-3	8.062-3	0.
La-141	1.426-4	3.180-4	1.442	1.442	0.
Ce-141	0.	0.	2.056	2.056	0.
Xe-142	0.	0.	0.	0.	0.
Cs-142	0.	0.	0.	0.	0.
Ba-142	0.	0.	0.	0.	0.
La-142	0.	0.	1.027-3	1.027-3	0.
Xe-143	0.	0.	0.	0.	0.
Cs-143	0.	0.	0.	0.	0.

TABLE 9.4-5 (SHEET 8 OF 8)

Component	Moisture Separator	Reheater	Charcoal Vessel Train	First Charcoal Vessel	Afterfilter
Isotope					
Ba-143	0.	0.	0.	0.	0.
La-143	0.	0.	0.	0.	0.
Ce-143	0.	0.	2.851-6	2.851-6	0.
Pr-143	0.	0.	2.980-6	2.980-6	0.
Xe-144	0.	0.	0.	0.	0.
Cs-144	0.	0.	0.	0.	0.
Ba-144	0.	0.	0.	0.	0.
La-144	0.	0.	0.	0.	0.
Ce-144	2.941-5	6.560-5	3.070+2	3.070+2	0.
Pr-144	2.933-5	6.540-5	3.070+2	3.070+2	0.
Halogens	-	-	2.680+7	2.680+7	-
N-13	6.522-1	1.449	2.652+2	6.233+1	2.565-1
N-17	0.	0.	0.	0.	0.
O-19	0.	0.	0.	0.	0.
TOTAL	9.992+4	2.228+5	3.395+9	9.206+8	7.448+4
Gas Kr + Xe	8.662+4	1.931+5	3.179+9	8.140+8	5.925+4
Solid daughters	1.327+4	2.968+4	1.362+8	2.596+7	1.513+4
Kr gas	4.222+4	9.412+4	2.503+8	5.057+7	2.889+4
Xe gas	4.440+4	9.902+4	2.928+9	7.635+8	3.036+4

TABLE 9.4-6

FRACTIONAL RELEASES OF COMPONENT ACTIVITY USED IN FAILURE DOSE CALCULATIONS

Component Evaluated	Activity Considered	Fractional Release
Off-gas condenser	Noble and activation gases particulates	1.0 1.0
Holdup pipe	Noble and activation gases particulates	0.20 0.20
Cooler-condenser	Noble and activation gases particulates	1.0 1.0
First charcoal vessel	Noble and activation gases iodine	0.10 0.01
All charcoal vessels	Noble and activation gases iodine	0.10 0.01

TABLE 9.4-7

RADIOLOGICAL DOSE - RECHAR SYSTEM FAILURE
(mrem/event)

Component and Activity Evaluated	Distance (m) 500	1000	1310	1500	2500	3500
Off-gas condenser						
Noble gases	.07	.02	.01	.01	.01	negl
Particulates	.20	.09	.06	.05	.02	.01
Sum	.27	.11	.07	.06	.03	.01
Holdup pipe						
Noble gases	2.1	0.84	0.71	0.65	0.36	0.22
Particulates	32.0	14.00	9.60	7.90	3.50	1.90
Sum	34.	15.	10.00	8.50	3.90	2.10
Cooler-condenser						
Noble gases	.04	.02	.01	.01	.01	.01
Particulates	.73	.32	.22	.18	.08	.04
Sum	.77	.34	.23	.19	.09	.05
Charcoal vessel train						
Noble gases	1.8	0.78	0.69	0.64	0.39	0.25
Halogens	33.0	23.00	18.00	16.00	9.30	5.80
Sum	35.	24.	19.	17.	9.7	6.1
First charcoal vessel						
Noble gases	0.57	0.26	0.23	00.21	0.13	0.08
Halogens	33.00	23.00	18.00	16.00	9.30	5.80
Sum	34.	23.	18.	16.	9.4	5.9

TABLE 9.4-8

MAJOR RADIOISOTOPES IN STEAM AT REACTOR NOZZLE

Coolant Activation Products

N-13	8.5×10^3 µCi/s
N-16	1.4×10^8 µCi/s
N-17	2.4×10^4 µCi/s
0-19	1.1×10^6 µCi/s
F-18	5.3×10^3 µCi/s

Halogens

~ 2×10^3 µCi/s (2% carryover)

Noncoolant Activation Products

~ 8×10^1 µCi/s (0.1% carryover)

Solid Fission Products

~ 2×10^0 µCi/s (0.1% carryover)

Noble Gases

~ 2×10^6 µCi/s

Design basis off-gas rate = 1×10^5 µCi/s per reactor of a diffusion mixture of noble gases referenced to 30-min decay.

TABLE 9.4-9

MAJOR RADIOISOTOPES IN STEAM IN MAIN CONDENSER

Coolant Activation Products

N-13	2.9×10^3 μCi
N-16	2.6×10^7 μCi
N-17	2.2×10^3 μCi
0-19	2.9×10^5 μCi
F-18	1.7×10^3 μCi

Halogens

~ 7×10^2 μCi (2% carryover)

Noncoolant Activation Products

~ 4×10^1 μCi (0.1% carryover)

Solid Fission Products

~ 7.5×10^1 μCi (0.1% carryover)

Noble Gases

~ 4×10^5 μCi

Design basis off-gas rate = 1×10^5 μCi/s per reactor of a diffusion mixture of noble gases referenced to 30-min decay.

10.0 AUXILIARY SYSTEMS

10.1 SUMMARY DESCRIPTION

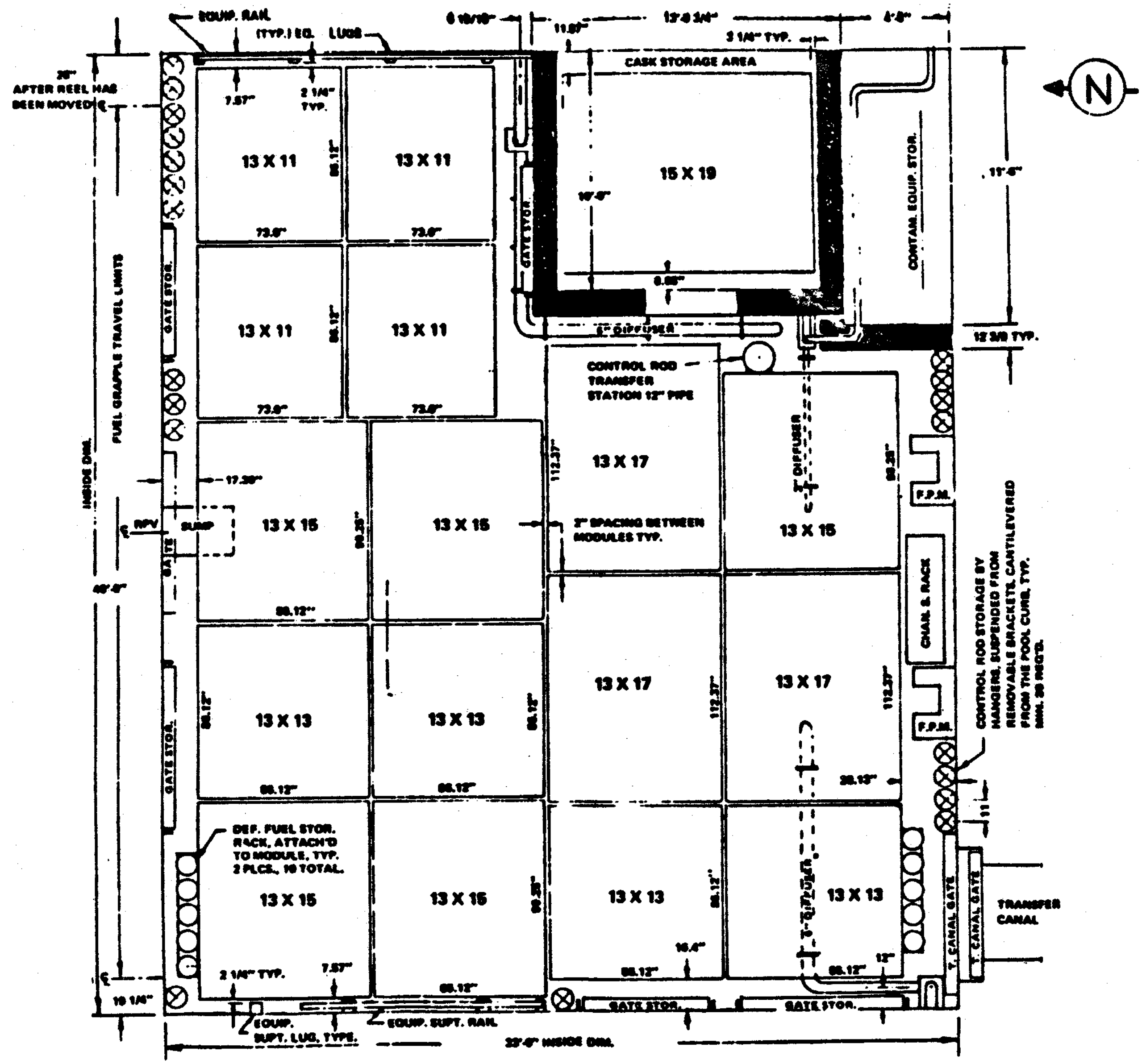
This section describes the objectives, design bases, system design, functional requirements, performance characteristics, safety considerations, and inspection and testing requirements of the reactor and plant auxiliary systems.

10.2 NEW FUEL STORAGE

See HNP-2-FSAR subsection 9.1.1 for a description of new fuel storage.

10.3 WET SPENT-FUEL STORAGE

See HNP-2-FSAR subsection 9.1.2 for a description of wet spent-fuel storage.



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HNP-1 HIGH-DENSITY FUEL STORAGE SYSTEM ARRANGEMENT

FIGURE 10.3-1

10.4 FUEL POOL COOLING AND CLEANUP SYSTEM (FPCCS)

See HNP-2-FSAR subsection 9.1.3 for a description of the FPCCS.

10.5 REACTOR BUILDING CLOSED COOLING WATER SYSTEM

10.5.1 POWER GENERATION OBJECTIVE

The power generation objective of the reactor building closed cooling water (RBCCW) system is to provide required cooling to the equipment located in the reactor building during planned operations.

10.5.2 POWER GENERATION DESIGN BASIS

The system is designed with sufficient redundancy and flexibility of components such that the system is continuously able to perform its power generation objective and to maintain a constant loop inlet temperature to equipment during planned operation. The RBCCW system removes heat from the reactor auxiliary systems equipment and their accessories.

10.5.3 DESCRIPTION

The RBCCW system supplies inhibited demineralized cooling water to the reactor auxiliary systems equipment and accessories to remove heat during normal and shutdown conditions. The equipment cooled by the RBCCW system includes the following:

- Two reactor recirculation pump seal and motor-bearing coolers.
- Two reactor recirculation pump motors adjustable speed drive (ASD) heat exchangers.
- One drywell clean radwaste sump cooler.
- Two control rod drive pump coolers.
- One reactor building clean radwaste sump cooler.
- Two reactor water cleanup (RWC) system pump coolers.
- One RWC system nonregenerative heat exchanger.
- Two fuel pool heat exchangers.
- Drywell pneumatic system compressors and aftercooler.

The system (drawing no. H-16009) consists of a closed loop containing 3 half-capacity pumps each rated at 2300-gal/min and 150-ft head at 105°F and 2 full-capacity heat exchangers each rated at a normal operating duty of 28.35 x 10^6 Btu/h.

The 1000-gal-capacity surge tank, located at the highest point of the loop, accommodates system volume changes, maintains static pressure in the loop, and provides a means for detecting gross leaks in the RBCCW system. Makeup water to the RBCCW system is supplied from the demineralized water system by means of the demineralized water transfer pumps. Surge tank level is maintained automatically by means of a level switch mounted locally. The surge tank is readily accessible during reactor operation for level adjustment. The tank overflow is connected to the chemical drain system. An inhibitor to limit corrosion is added to the water, as necessary, by means of a chemical additive tank and pump.

The common discharge header for the pumps is monitored for low pressure. Low discharge pressure also automatically starts the standby pump. A pressure indicator is located at the outlet of each RBCCW heat exchanger for pressure testing. Temperature elements located on the common cooling water pump suction line indicate remotely the temperature of the cooling water in the main control room. The RBCCW system is maintained at < 105°F at the outlet of the heat exchanger. Heat rejection is through the loop heat exchangers cooled by the plant service water (PSW) system.

Any possible leakage from the reactor auxiliary systems equipment will be into the RBCCW closed loop. The RBCCW system is monitored continuously for radioactivity by the process radiation monitoring system.

The following conditions alarm in the main control room:

- High-surge tank level.
- Low-surge tank level.
- RBCCW heat exchangers outlet header low temperature.
- RBCCW heat exchangers outlet header high temperature.
- High radiation level.
- Low flow to recirculation pump seal coolers.
- High recirculation pump seal cooler temperature.
- High recirculation pump motor bearing cooler temperature.

The RBCCW heat exchanger and pump data are listed in table 10.5-1.

In normal operation, two pumps and one heat exchanger are operated. During the reactor blowdown operation, excess primary coolant is discharged to the main condenser or radwaste storage. To attain the low temperature required for discharge of coolant to either the condenser or the radwaste system, a higher-than-normal amount of heat is transferred to the RBCCW system by the nonregenerative heat exchanger.

The maximum design temperature of the RBCCW is 105°F, based on utilizing service water for cooling the RBCCW heat exchanger at a design service water temperature of 95°F. A single RBCCW heat exchanger has a normal design heat load of 28 x 10^6 Btu/h with the above service water temperatures. The RBCCW system design heat load for the reactor blowdown mode of operation is 35.0 x 10^6 Btu/h. Based on plant operating experience, a single RBCCW heat exchanger has sufficient heat removal capability to maintain the RBCCW system supply temperature below the design limit of 105°F during the reactor blowdown mode of operation. The system has been designed to allow the optional use of both RBCCW heat exchangers.

The equipment cooled by RBCCW was reviewed for any heat load impact associated with operation at 2804 MWt and an increase of the service water temperature to 97°F. The actual heat load to RBCCW remains within the heat removal capability for the system. Therefore, the heat exchanger has sufficient heat removal capability to maintain the RBCCW system supply temperature below the design limit of 105°F with no increase in the cooling water flow rate.

The RBCCW system functions as an intermediate barrier between nuclear system equipment and the PSW system. A detector is located in the system to continuously monitor radioactivity level. On detection of a high radiation level, an alarm is automatically set off in the control room.

Operation of the RBCCW system is not vital to safe shutdown of the plant under normal or accident conditions, and failure of any component of this system will not cause a significant release of radioactivity.

The RBCCW pumps can be operated on emergency power after the plant safety shutdown conditions are met.

10.5.4 INSPECTION AND TESTING

Pumps in the RBCCW system are proven operable by use during normal plant operations. Motor-operated isolation valves are tested to assure capablity of opening and closing by operation of the manual switches in the main control room and observation of the position lights.

TABLE 10.5-1

REACTOR BUILDING CLOSED COOLING WATER SYSTEM EQUIPMENT DATA

RBCCW Pumps

Quantity	Three 50% capacity each
Type	Horizontal, centrifugal
Flow and head	2300 gal/min at 150-ft total dynamic head
Material	
Casing	Cast iron
Impeller	Bronze
Shaft	Stainless steel
Voltage/phase/cycle	550 volt/3 phase/60 Hz
RPM at full load	1770

RBCCW Heat Exchangers

Quantity	Two 100% capacity each
Type	Horizontal, shell and tube
Duty	28.35 x 10^6 Btu/h
Shell design	
Pressure/temperature	150 psig/200°F
Material	Carbon steel
Flow medium	Inhibited demineralized water
Tube design	
Pressure/temperature	150 psig/200°F
Flow medium	River water

10.6 RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM

10.6.1 POWER GENERATION OBJECTIVE

The power generation objective of the residual heat removal service water (RHRSW) system is to supply water to the residual heat removal (RHR) system for heat removal during reactor shutdown.

10.6.2 POWER GENERATION DESIGN BASES

The RHRSW system is designed:

A. To supply a reliable source of cooling water to the RHR system.

B. For remote manual initiation.

C. To limit the possibility of any radioactive material release to the environment.

10.6.3 SAFETY OBJECTIVE

The safety objective of the RHRSW system is to provide a reliable supply of cooling water for decay heat removal from the RHR system under post-accident conditions.

10.6.4 SAFETY DESIGN BASES

The RHRSW system is designed to:

A. Withstand the design basis earthquake without impairing its function.

B. Have the capacity and redundancy to provide cooling water to the RHR system under post-accident conditions.

C. Be operable during loss of offsite power.

10.6.5 DESCRIPTION

The RHRSW system consists of four 4000-gal/min pumps, valves, controls, instrumentation, and necessary piping as shown on drawing no. D-11004. A positive differential pressure is maintained between the RHRSW system and the RHR system to preclude leakage of radioactive material to the RHRSW system; i.e., to the river. RHRSW is provided with two divisions to allow each system loop to operate independently. Two normally closed motor-operated crossover valves provide system flexibility so that any division I or division II operable pump may be lined up with any operable pump of the other division to supply the heat exchanger of the other division. Additionally, two manual isolation valves provide a normally closed crossover between division I and division II. The system design pressure is 450 psi; operating pressure is 415 psi.

The design characteristics of the RHRSW pumps for HNP-1 are shown on drawing no. S-56429. Actual flows and pressures may vary from nominal; however, the minimum acceptable performance of the pumps is verified by the Inservice Test Program. At the nominal flow of 4000 gal/min, the net positive suction head required is 29 ft.

The capability is provided to inject (as required) diluted solutions of sodium hypochlorite, sodium bromide, a corrosion inhibitor, and a silt dispersant into the RHRSW system to control organic biofouling, corrosion, and silt deposition in the pipe lines and heat exchangers.

Both RHRSW divisions cross-connect to the corresponding PSW division. These cross-connections shall not be used during normal or design basis accident conditions at the plant. The cross-connections between RHRSW and PSW are provided with manual, double isolation valves which shall be maintained closed, except for periodic plant maintenance activities such as dead-leg flushing. The RHRSW-PSE cross-connections are only to be used in response to a beyond design basis external event (BDBEE).

10.6.6 SAFETY EVALUATION

The intake structure which houses the RHRSW pumps is of Class I seismic design. The intake structure is designed to draw water from the Altamaha River under the design flood or minimum river flow conditions.

The RHRSW system is designed with sufficient redundancy so that no single active system component failure can prevent it from achieving its safety objective. Two independent loops, each with 100% pump and heat exchanger capacity, are provided.

10.6.7 INSPECTION AND TESTING

The equipment and system were inspected and tested upon installation.

The RHRSW equipment and system are periodically inspected and tested. The plant service water and RHRSW inspection program described in HNP-2-FSAR subsection 18.2.13 is designed to detect wall thickness degradation, fouling, or cracking.

10.6.8 INSTRUMENTATION APPLICATION

The RHRSW system is designed for remote manual initiation and operates during testing, reactor shutdown, containment spray, and suppression pool cooling modes. The system is stopped automatically should low pressure coolant injection (LPCI) operation be required.

A flow control valve is provided on the RHR heat exchanger service water outlet. Its function is to maintain the pressure on the tube side above the pressure on the shell side inlet at all cooling water flowrates, thereby preventing reactor water leakage into the river water. Pressure switches on the service water inlet to the RHR heat exchanger provide a permissive for throttling of the flow control valve upon sensing sufficient pressure indicative of RHRSW availability to that RHR heat exchanger. This permissive may be overridden by means of a key lock switch so that the RHRSW pump may be started with the heat exchanger discharge valve(s) open. The pressure interlock is manually restored with the key lock switch once the pump is started.

Pressure and flow indicators located in the main control room inform the operator of pump performance and/or line integrity.

Temperature elements located at the RHRSW discharge line from the RHR heat exchanger signal any abnormal temperature of RHRSW and sound an alarm in the main control room.

The RHRSW pump motors are cooled by water from the plant service water system.

A low-flow bypass is provided from the pump discharge to the intake structure. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. A pressure control valve limits the bypass flow.

TABLE 10.6-1

RHRSW SYSTEM PRINCIPAL DESIGN PARAMETERS

Pumps

Quantity	4 half capacity
Fluid	River water
Type	Vertical turbine
Nominal flow and head (each)	4000 gal/min at 955-ft total dynamic head
Material	
Casing	Cast steel or stainless steel
Shaft	Stainless steel
Impeller	Bronze or Stainless Steel
Motor	
Size	1250 hp
Voltage	4160
Phase	3
Cycle	60
rpm	1770

System Requirements

Service water pressure at RHR heat exchangers is at least 20 psi greater than reactor water pressure at the heat exchangers; thus, any leakage goes into the reactor water.

10.7 PLANT SERVICE WATER SYSTEM

10.7.1 POWER GENERATION OBJECTIVE

The power generation objective of the plant service water (PSW) system is to provide cooling water for plant services and provide makeup water for the condenser circulating water system.

10.7.2 POWER GENERATION DESIGN BASES

The PSW system is designed to:

A. Provide screened cooling water to the plant during normal operating and shutdown conditions.

B. Provide makeup water to the main circulating water system.

10.7.3 SAFETY OBJECTIVE

The safety objective of the PSW system is to provide a reliable supply of cooling water to systems and equipment required for accident conditions.

10.7.4 SAFETY DESIGN BASES

The PSW system is designed to:

A. Withstand the design basis earthquake (DBE) without impairing its function.

B. Have sufficient capacity and redundancy to provide reliable cooling.

C. Be operable during loss-of-offsite power (LOSP).

10.7.5 DESCRIPTION

The PSW system (drawing nos. D-11001, H-11024, H-11600, H-16011, and H-11609 through H-11611) consists of four, one-third-capacity vertical wet pit service water pumps located in the river intake structure, distribution piping, and controls. Automatic self-cleaning strainers are provided in the discharge line to remove suspended matter from the pumped water.

The PSW system provides cooling water to:

- The reactor building closed cooling water system heat exchangers (section 10.5).

- The turbine building heat exchangers associated with power conversion systems located in the turbine building.

- The standby diesel generators heat exchangers.

- The reactor building sample coolers.

- The equipment area cooling system (section 10.18).

- The main control room environmental control system (section 10.17).

Three service water pumps are required for normal operation; however, only one pump from each division is required for startup, shutdown, and emergency shutdown. The fourth PSW pump is a standby pump available for use if one of the other three PSW pumps fails, if emergency conditions exist, or if plant conditions (such as increased heat load due to high ambient temperatures) warrant its use. The pumps are controlled so that if the operating pumps cannot maintain the required system pressure, the standby pump starts automatically. A separate standby diesel generator PSW pump is supplied to service standby diesel generator 1B. The standby diesel generator PSW pump is considered HNP-2 equipment.

Figure 10.7-1 shows a typical PSW pump curve. When the PSW pumps are delivering their rated capacity of 8500 gal/min, 48 in. of submergence over the pump suction bell is required to provide adequate net positive suction head (NPSH) and preclude vortexing. The actual PSW pump suction elevation, is at 57.2 ft mean sea level (msl); thus, the minimum water level in the pump well for maximum capacity PSW pump operation is 57.2 ft plus the 4 ft of required submergence, or 61.2 ft. This is equal to a river level at the intake structure of 61.3 ft msl with allowance for a 0.1-ft head loss through the trash racks and travelling screens. When the plant is operating at full-power, only three of the four PSW pumps are required, each delivering ~ 7840 gal/min; thus, a water level of 61.2 ft in the pump well is more than adequate for full power operation.

Shutdown cooling of the plant requires only one PSW pump delivering 4428 gal/min. The Technical Specifications require plant shutdown if the water level, as measured in the pump well, decreases to < 60.5 ft MSL. This is well above the minimum required to operate at the throttled level (7000 gal/min) and considerably more than required for single-pump operation for plant shutdown.

Both PSW divisions cross-connect to the corresponding RHRSW division. These cross-connections shall not be used during normal or design basis accident conditions at the plant. The cross-connections between PSW and RHRSW are provided with manual double isolation valves which shall be maintained closed, except for periodic plant maintenance activities such as dead-leg flushing. The PSW-RHRSW cross-connections are only to be used in response to a beyond design basis external event (BDBEE).

The capability is provided to inject (as required) sodium hypochlorite, a corrosion inhibitor, and a silt dispersant into the systems to control organic biofouling, corrosion, and silt deposition in the pipe lines and heat exchangers. Drawing no. H-43801 shows the schematic arrangement of the water treatment system components/piping.

10.7.6 SAFETY EVALUATION

The PSW system pumps are located in a Category I seismic design intake structure. Also, the portions of the system including the pumps which are required for emergency cooling are designed as a Category I seismic system and meet the single-failure criteria. Thus the loss of one division does not prevent the system from delivering the minimum service water required for safe shutdown of the plant.

Water for equipment cooling is taken from the river via the intake structure by four service water pumps and distributed by two header pipes to different areas of use. These areas are the diesel generator building, the reactor and control building, and the turbine building. There is no safety-related equipment requiring cooling water in the turbine building and during certain emergency conditions, LOSP and loss-of-coolant accident (LOCA), the supply to this area is automatically cut off. All piping except that in the turbine building and the discharge to the flume is Seismic Category I.

During normal power production, three pumps are required, but one pump has enough capacity to supply all the demand under shutdown and emergency conditions. Upon receipt of an LOSP or a LOCA signal, the system is divided into two redundant systems (referred to herein as Divisions I and II) automatically and one pump in each safeguard Division is automatically started. All pumps can be powered by the offsite or the onsite sources as required.

While operating in the normal mode and supplying water to the turbine building, the headers for both divisions are interconnected by the turbine building supply header because three pumps are required for this operation. Motor-operated valves P41-F310A, B, C, and D are provided to isolate the turbine building supply header. The following signals will cause these valves to close, isolating the turbine building supply header:

- Manual close signal.
- Turbine building (condenser room) flooding.
- LOSP.
- LOCA.

Once these valves are closed, there is no intertie between the two division headers.

Flow from each division into the turbine building supply header is monitored by a system of orifices and differential pressure switches. High flow into the turbine building supply header (indicative of a possible pipe break) is alarmed in the main control room (MCR). A short time delay (2-5 s) is introduced into the flow switch circuit to allow for normal surges within the system.

The cooling water to diesel generator 1B is supplied from the standby service water pump 2P41-C002 and is discussed in HNP-2-FSAR paragraph 9.2.1.4. The capability also exists to supply diesel generator 1B from HNP-1 PSW.

The cooling water to MCR air-conditioner 1Z41-B008B is normally supplied by Unit 1, Division I, and/or Unit 2, Division II PSW systems. The MCR air-conditioner 1Z41-B008B can be manually aligned to the Division II cooling water source by manually closing Division I valve P41-F422A and redundant Division I valve P41-F421A, and manually opening Division II valves P41-F421B and P41-F420B.

Low pressure in each main header and each MCR air-conditioning unit header is alarmed in the MCR on four separate annunciator windows. Low pressure to each diesel is annunciated on separate annunciators in the MCR.

In the normal operating mode, the pump controls are manual with the operator selecting which pumps are put into service. The operator may also position the control switch of remaining pump(s) in the STANDBY position and, upon low pressure in the header, the standby pump or pumps are automatically started by pressure switches P41-N512 and P41-N513.

With the LOSP, the three diesels are automatically started and connected to the respective 4160-V buses, and the load sequencers automatically start one pump in each division. The diesel engines can operate for at least 3 min without service water flow through the coolant heat exchanger before reaching an abnormally high temperature; thus, the time period involved in starting the diesels and pumps has no significance.

While operating in the HOT SHUTDOWN mode with an LOSP, diesels 1A and 1C are used to ensure both divisions of pumps, valves, controls, etc., have power. Either 600-V bus 1C (Division I) or bus 1D (Division II) may be supplied from diesel 1B via 4160-V transformer 1CD, but this requires previous manual connection of the 600-V bus disconnecting links between the 600-V switchgear and transformer 1CD.

The equipment on drawing nos. D-11001, H-11024, H-11600, H-16011, and H-11609 through H-11611 that may require PSW during and following an accident are as follows:

- Diesel generators.
- Residual heat removal (RHR) pump seals heat exchangers.
- RHR pump room area coolers.
- High-pressure coolant injection (HPCI) pump room area coolers.
- Control room air-conditioning units.

PSW supply piping to the above equipment is designed to the B31.1 piping code, was upgraded to be equivalent to B31.7 Class III, and was analyzed for seismic loads.

(See HNP-2-FSAR supplement 3.7A.B.) The valves in the system were purchased to the American Society of Mechanical Engineers (ASME) Pump and Valve Code, Class III, or to the B31.1 Piping Code, and also to seismic requirements. The PSW pumps were purchased according to ASME Code, Sections VIII and IX, and the draft of ASME Pump and Valve Code with specifications written to meet Class III of the ASME Pump and Valve Code draft. Seismic analysis was also performed on the pumps. (See table A.2-3 for additional detail on upgraded piping and the applicable codes used on the PSW system.)

A PSW system single-failure analysis was performed in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment." The analysis evaluates individual single failures of all active components of the safety-related portion of the PSW system assuming a LOCA, an LOSP, and a seismic event. The analysis demonstrates that the PSW system has adequate redundancy.

During normal operation, PSW is supplied to the following equipment:

- Diesel generator.
- Control room air-conditioning units.
- RHR pump seal (during test).
- RHR and CS pump room area cooler (during test).
- HPCI pump room area cooler (during test).
- RCIC pump room area cooler (during test).
- Control rod drive pump room area cooler.
- Drywell cooler.
- Computer room air-conditioner.
- Water sampling room air-conditioner.
- Chemical lab air-conditioner.
- Hot instrument shop air-conditioner.
- Reactor feed pump turbine oil cooler.
- Reactor building closed cooling water heat exchanger.
- Generator hydrogen cooler.
- Stator cooler.

- Main turbine oil cooler.

- Electrohydraulic control fluid heat exchanger.
- Recombiner.
- Radwaste building closed cooling water heat exchanger.[a]
- Vacuum pump.
- Generator bus cooler.
- Screen wash.
- Waste gas treatment building.
- PSW pump motor cooler.
- Residual heat removal service water (RHRSW) pump motor cooler.
- Reactor building sample cooler.
- Reactor building sample panel chiller.
- Condensate pump motor cooler.
- Condensate booster pump oil cooler.
- Demineralized water chiller.
- CO_2 storage tank room air-conditioner.

The following spectrum of events was considered in the design of the emergency cooling equipment:

- LOSP.
- LOCA.
- Loss of normal ventilation.

- Seismic events.

- Single failures of active equipment.

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a. This equipment is normally not in service.

Under the above emergency conditions, PSW is supplied to the following equipment to meet accident heat loads with a river water temperature 97°F[a]:

- Diesel generator.

- Control room air-conditioning units.

- RHR pump seals heat exchanger.

- RHR and CS pump room area cooler.

- HPCI pump room area cooler.

- RCIC pump room area cooler.

- Drywell air cooler.[b]

- Control rod drive pump room cooler.[b]

- PSW pump motor cooler.

- RHRSW pump motor cooler.

10.7.7 INSPECTION AND TESTING

Pumps, other components, and the system were inspected and tested after installation and prior to operation of the unit.

Additionally, the PSW system is proven operable by its use during normal plant operation.

The PSW and RHRSW inspection program described in HNP-2-FSAR subsection 18.2.13 is designed to detect wall thickness degradation, fouling, or cracking.

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a. Actual flowrate varies depending upon system alignment and demand.

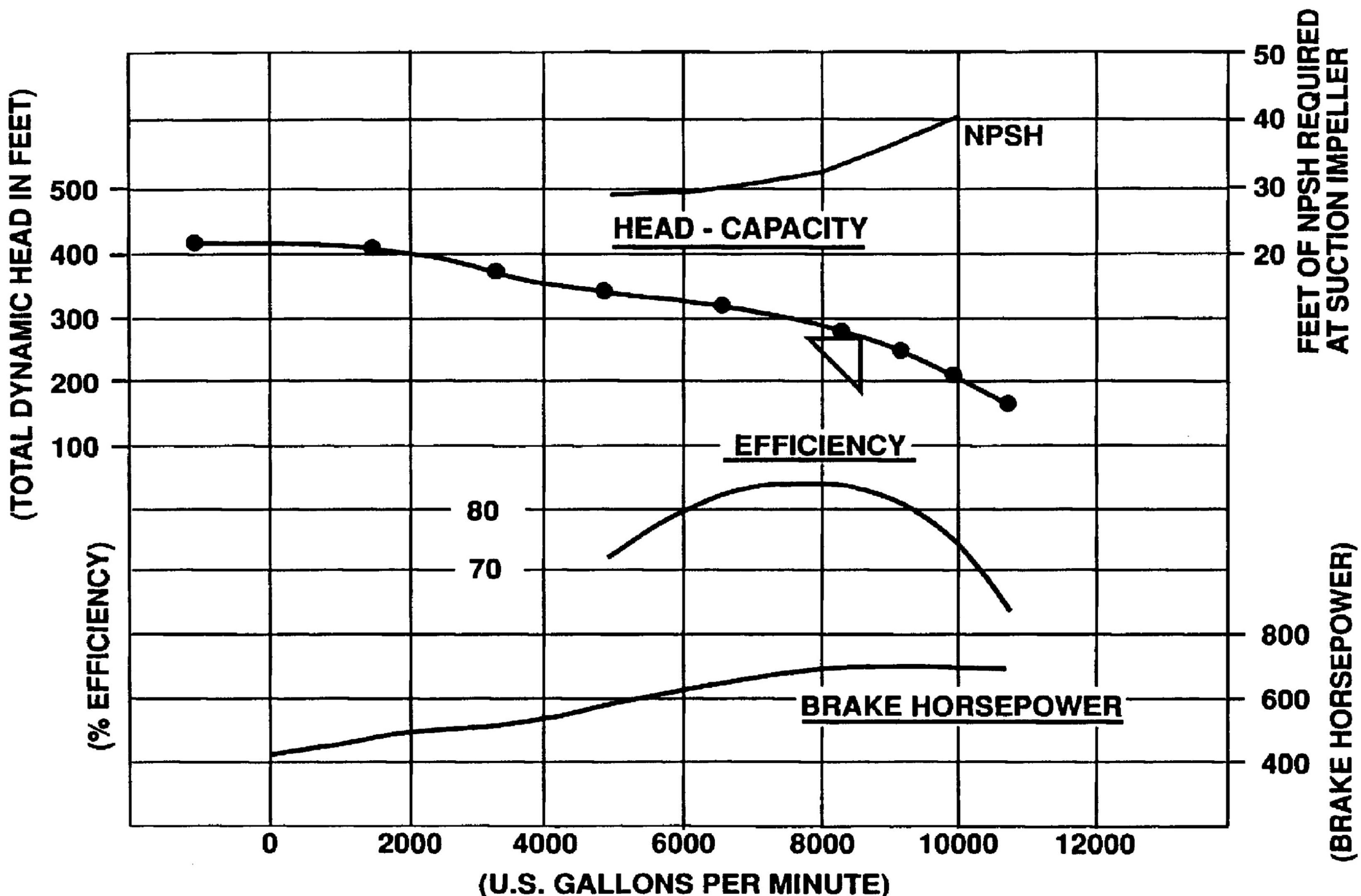
b. This equipment is not required for emergency conditions; however, the normal LOCA valve lineup has flow to this equipment.

TABLE 10.7-1

PSW SYSTEM EQUIPMENT DATA

PSW Pumps	
Quantity	4, one-third-capacity
Type	Vertical turbine
Rated flow and head each	8500 gal/min at 275 ft[a]
Material	
Casing	Stainless steel
Impeller	Stainless steel
Shaft	Stainless steel
Motor	
Size	700 hp
Voltage	4160
Phase	3
Cycle	60
rpm	1180
Automatic Strainers	
Quantity	2 full capacity
Type	Automatic self-cleaning
Capacity	25,500 gal/min
Pressure drop	2 psi

a. This is a nominal reference value.



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

PSW PUMP CHARACTERISTICS
(TYPICAL)

FIGURE 10.7-1

10.8 FIRE PROTECTION SYSTEM

The plant fire protection system is described in the ***Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR).***

10.9 HEATING, VENTILATION, AND AIR-CONDITIONING (HVAC) SYSTEMS

10.9.1 POWER GENERATION OBJECTIVE

The power generation objectives of the HVAC systems are to:

- Control plant air temperatures and the flow of airborne radioactive contaminants to ensure operability of plant equipment, and accessibility and habitability of plant buildings and compartments.

- Minimize the potential release of radioactive materials to the outside environs.

10.9.2 POWER GENERATION DESIGN BASES

The HVAC systems are designed to:

- Provide temperature control and air movement control, including a filtered fresh air supply, for personnel comfort.

- Optimize equipment performance by the removal of the heat dissipated from the plant equipment.

- Minimize the potential of exhaust air entering into the supply air intake by exhausting at an elevated point via the reactor building vent plenum.

- Provide for air movement from lesser to progressively greater areas of radioactive contamination potential.

- Minimize the potential release of particulates and airborne radioactive materials (especially iodine) to the environs by filtering the exhaust air from the potentially contaminated areas.

10.9.3 DESCRIPTION

10.9.3.1 General

The primary purpose of all ventilation systems is to remove heat produced by equipment, piping, and motors and to minimize the potential release of airborne radioactive materials to the environs. Design flowrates are sufficient to control cross-flow between areas of different contamination levels and to control ambient temperatures.

Sufficient ventilation supply air is provided to control contamination and is filtered before being supplied to the different areas. Adequate controls are provided to monitor the performance of the ventilation systems. In addition, standby equipment is installed in HVAC systems that are essential to maintain proper air pressures or temperatures for the safe and continuous operation of the plant.

10.9.3.2 Reactor Zone Ventilation System

The reactor zone ventilation system (below the refueling floor), as shown on drawing no. H-16005, has two supply fans. Normally, one supply fan operates while the other supply fan is on standby. Filtered outside supply air is ducted to different areas of the reactor building. If an operating fan fails during normal operation, the standby fan starts automatically and an alarm is annunciated in the main control room (MCR).

The reactor zone ventilation system exhaust is divided into two subsystems, the accessible area exhaust system and the inaccessible area exhaust system. Each exhaust subsystem has two exhaust fans, with one fan normally operating while the other fan is on standby. If the operating fan fails, the standby fan starts automatically and an alarm is annunciated in the MCR.

The exhaust from the following areas is connected to the accessible area exhaust subsystem and is ducted by the operating accessible area exhaust fan to the outside environs via the reactor building vent plenum:

- Working floor areas.

- Control rod drive area.

- ASD areas.

The exhaust from the accessible area is continuously monitored by two radiation monitors. Should a release of radioactivity be detected in the accessible area exhaust by one of the monitors, the accessible area exhaust fans are automatically de-energized and the exhaust isolation dampers are automatically closed, the ventilation supply airflow is reduced to ~ 50% capacity, and the bypass damper between the accessible area and the inaccessible area duct system is opened. During this period, all exhaust from the reactor zone is filtered by inaccessible area exhaust filter trains and is ducted to the outside environs via the reactor building vent plenum.

The exhaust from the following areas is connected to the inaccessible area exhaust subsystem:

- Fuel pool pump and heat exchanger area.

- Reactor water cleanup system area.

- Main steam pipe chase area.

- Residual heat removal and core spray pump rooms.

- High-pressure coolant injection room.
- Torus chamber room.

The exhaust from these areas is filtered by two 50% capacity filter trains and is ducted by the operating inaccessible area exhaust fan to the outside environs via the reactor building vent plenum. Each filter train is rated for 16,000 ft^3/min and consists of a bank of prefilters, a bank of carbon adsorbers to minimize iodine releases, and a bank of high-efficiency particulate air (HEPA) filters to minimize particulate releases. Radiation monitors survey the bank performance with high-level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe.

Each prefilter is rated at 1000 ft^3/min and is designed for 85 to 90% efficiency, in accordance with the National Institute of Standards and Technology (NIST) atmospheric stain (dust spot) test method. The charcoal adsorber is mounted in a dual-tray module drawer and has a nominal rating of 333 ft^3/min. Each drawer contains ~ 45 lb of TEDA-impregnated charcoal with expected efficiency of 99%. Each HEPA filter is rated for 1000 ft^3/min and maximum total dioctyl phtalate (DOP) smoke penetration of 0.03% of upstream concentration with 0.3-μm aerosols.

Two channels of radiation monitors are installed to monitor the inaccessible area exhaust. Should a release of radioactivity be detected in the inaccessible area exhaust by one of the above monitors, the supply and exhaust fans (accessible area and inaccessible area) are shut off, the secondary containment isolation dampers are closed, and the standby gas treatment system (SGTS) is started and annunciated. The SGTS filters and discharges the air to the main stack.

A separate fan supplies air to the drywell during purge. The SGTS removes purge air from the drywell during this operation. The SGTS is discussed in paragraph 5.3.3.3.

10.9.3.3 Refueling Zone Ventilation System

The refueling zone ventilation system, as shown on drawing no. H-16014, has two supply fans. Normally, one supply fan operates while the other supply fan is on standby. Filtered outside supply air is ducted to the operating floor. If an operating fan fails during normal operation, the standby fan starts automatically, and an alarm is annunciated in the MCR.

The exhaust air is ducted through the openings located at the perimeter of the spent-fuel pool and from the refueling floor to two 50% capacity filter trains. Two exhaust fans, one normally operating and the other on standby, exhaust the filtered air to the outside environs via the reactor building vent plenum. In addition, provisions are made to manually exhaust the air from the reactor pool and dryer separator pool through the filter trains during refueling outages. Each filter train is rated for 15,000 ft^3/min and consists of a bank of prefilters, a bank of carbon adsorbers, and a bank of HEPA filters to minimize the potential of particulate and iodine releases. Radiation monitors survey the bank performance with high-level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe.

Each prefilter is rated at 1000 ft^3/min and is designed for 85 to 90% efficiency, in accordance with the NIST atmospheric stain (dust spot) test method. Each charcoal adsorber is mounted in a dual-tray module drawer and has a nominal rating of 333 ft^3/min. Each drawer contains ~ 45 lb of TEDA impregnated charcoal with an expected efficiency of 99%. Each HEPA filter is rated for 1000 ft^3/min and maximum total DOP smoke penetration of 0.03% of upstream concentration with 0.3-μm aerosols.

Two channels of radiation monitors are installed in the exhaust duct. Should a release of radioactivity be detected in the exhaust duct by the above monitors, the refueling zone supply and exhaust fans are shut off, the isolation dampers are closed, and the SGTS is started and annunciated. A hot water heating coil is provided in the exhaust duct to reduce the relative humidity of the exhaust air to 70% prior to filtration.

In addition, the refueling zone ventilation system is used for reactor pressure vessel head venting following the reactor shutdown and before lifting off the head. This mode of operation is accomplished by manually opening the remote operated valves.

10.9.3.4 Turbine Building Ventilation System

The turbine building ventilation system, as shown on drawing no. H-16037, consists of two supply fans. Normally, one supply fan operates while the other supply fan is on standby. Filtered outside supply air is ducted to the different areas of the turbine building. The supply air may be augmented by opening the turbine building railroad door. If an operating fan fails during normal operation, the standby fan starts automatically, and an alarm is annunciated in the MCR.

As part of the implementation of an alternative source term (AST) (reference HNP-2-FSAR subsection 15.1.11), the exhaust only portion of the turbine building HVAC is credited with purging the area around the main control room following a loss-of-coolant accident (LOCA), main steam line break accident (MSLBA), and control rod drop accident (CRDA). The credited exhaust rate is 15,000 cfm:

- With sufficient redundancy to ensure reliable operation within 9 h of a LOCA, main steam line break (MSLB), or CRDA.
- To purge the area around the MCR to reduce the activity available for leakage into the MCR following a LOCA, MSLB, or CRDA.
- To operate without being dependent upon the availability of offsite power supplies.
- With sufficient redundancy so that no single active system component failure can prevent the system from fulfilling its safety function.

The exhaust air is ducted from the following areas:

- Main condenser area.

- Main steam turbine area.
- Reactor feed pump rooms.
- Reactor building closed cooling water pump room.
- Cold lab and water analysis lab fume hoods - control building.
- Radiochemical laboratory exhaust fume hoods - control building.

The aforementioned areas are maintained at a slight negative pressure in relation to the adjoining areas to ensure inward leakage of air to the potentially contaminated areas. The exhaust from the above areas is filtered by two 50% capacity filter trains and is ducted to the outside environs via the reactor building vent plenum by one normally operating exhaust fan. If the operating fan fails, the standby fan starts automatically, and an alarm is annunciated in the MCR.

The following describes the changes implemented to turbine building ventilation exhaust system to support the AST credited function of purging the area around the main control room following a LOCA, MSLBA, and CRDA. The credited exhaust rate is 15,000 ft^3/min. The turbine building ventilation exhaust system consists of four exhaust fans, two per unit, and associated exhaust ductwork. The exhaust fans are normally supplied by nondiesel-backed power; however, after the referenced DBAs with loss of offsite power (LOSP), each fan is capable of being supplied with diesel-backed power by manually transferring power via a manual transfer switch positioned to the diesel-backed power source. Also, the associated solenoid valves are powered with diesel-backed power that controls operation of the fan inlet dampers required for exhaust fan operation. The operator manually aligns each associated fan manual transfer switch to the alternate diesel-backed power supply position. Operator manual action is administratively controlled after the initial 10 min post DBA. Finally, noninterruptible instrument air with backup nitrogen is provided to the necessary damper air actuators to increase system reliability. Finally, applying the precedent established by NRC approval of the nonsafety-related main steam isolation valve alternate leakage treatment path, seismic verifications were developed and are maintained to demonstrate that the HNP-1 and HNP-2 turbine building exhaust ductwork will remain in place and maintain exhaust flow in the event of a design basis earthquake. These verifications are based on earthquake experience data and use the methodology documented in Electric Power Research Institute (EPRI) Technical Report 1007896, “Seismic Evaluation Guidelines for HVAC Duct and Damper Systems,” dated April 2003.

Each filter train is rated for 15,000 ft^3/min and consists of a bank of prefilters, a bank of carbon adsorbers, and a bank of HEPA filters to minimize the potential of particulate and iodine releases. Radiation monitors survey the bank performance with high-level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe.

Each prefilter is rated at 1000 ft^3/min and is designed for 85 to 90% efficiency in accordance with the NIST atmospheric stain (dust spot) test method. Each charcoal adsorber is mounted in a dual-tray module drawer and has a nominal rating of 333 ft^3/min. Each drawer contains

~ 45 lb of TEDA impregnated charcoal with an expected efficiency of 99%. Each HEPA filter is rated for 1000 ft^3/min and maximum total DOP smoke penetration of 0.03% of upstream concentration with 0.3-μm aerosols.

In addition to the ventilation system, a recirculating cooling system is provided for the turbine building. The recirculating cooling system consists of 13 fan coil units located in different areas of the turbine building. These units remove the heat dissipated from the equipment, piping, and electrical devices. Each fan coil unit consists of a vaneaxial fan and chilled water cooling coil mounted in a sheet metal housing. The fan coil units are served by the turbine building chilled water system. The turbine building chilled water system consists of two 750-ton nominal water cooled chillers, two cooling towers, chilled and condenser water pumps, separate water treatment systems for the chilled and the condenser water loops, an air separator, piping and controls. The chilled water loop system consists of the chiller-evaporator, chilled water pumps and the various fan coil units in the turbine building. The condenser water loop consists of the chiller-condenser, condenser water pumps and the cooling towers. Normally, one chiller, one cooling tower and one set of (chilled and condenser water) pumps are in operation, and this equipment can be operated in any combination. The other chiller, cooling tower and set of pumps are maintained on standby, and if needed, can be manually placed in service. The chilled water system is manually operated from the chiller control panel located in the turbine building on el 164 ft. The cooling tower can be operated from the local control panel located in the cooling tower enclosure. The makeup water supply to the cooling towers is from the sanitary water system. The turbine building chilled water system is shown on drawing nos. H-16326 and H-16327.

Hot water unit heaters are provided to maintain 50°F at the operating floor of the turbine building during the winter. However, analysis indicates that the design temperature of the turbine building operating floor can be maintained with internal heat loads; therefore, use of the hot water unit heaters is not necessary.

10.9.3.5 Radwaste Building and Radwaste Building Addition Ventilation System

The radwaste building ventilation system shown on drawing no. H-16008 and the radwaste building addition ventilation system shown on drawing no. H-16512 are identical in design concept. Each system consists of two supply fans. Normally, one supply fan operates while the other supply fan is on standby. Filter supply air is ducted to the different floors of the building. If an operating fan fails during normal operation, the standby fan starts automatically, and an alarm is annunciated in the MCR.

The exhaust from different areas is filtered by two 50% capacity filter trains and is ducted by the normally operating exhaust fan to the outside environs via the reactor building vent plenum. If the operating fan fails, the standby fan starts automatically, and an alarm is annunciated in the MCR.

Each filter train consists of a bank of prefilters, a bank of carbon adsorbers, and a bank of HEPA filters to minimize the potential of particulate and iodine releases. Radiation monitors survey the bank performance with high-level annunciation in the MCR. These monitors are backed up by the reactor building vent plenum isokinetic probe.

Each prefilter is rated at 1000 ft^3/min and is designed for 85 to 90% efficiency in accordance with the NIST atmospheric stain (dust spot) test method. The charcoal adsorber is mounted in a dual-tray module drawer and has a nominal rating of 333 ft^3/min. Each drawer contains ~ 45 lb of TEDA impregnated charcoal with an expected efficiency of 99%. Each HEPA filter is rated for 1000 ft^3/min and maximum total DOP smoke penetration of 0.03% of upstream concentration with 0.3-μm aerosols.

The radwaste control room is cooled by two HVAC systems, one considered as the primary system and the other as backup. The primary HVAC system consists of an air handling unit with a fan, a chilled water cooling coil and prefilters, and temperature controls. The cooling coil in the primary air handling unit is served by the Unit 1 reactor building chilled water (1P65) system. A thermostat in the radwaste control room modulates the three-way control valve to regulate water flow to the cooling coil for maintaining acceptable temperature in the room. The backup HVAC system consists of an air handling unit with a fan and a chilled water cooling coil. The cooling coil in the backup unit is served by the turbine building chilled water (1P63) system. Unlike the primary system, the backup system does not have any temperature control features. The backup HVAC system has a lower cooling capacity than the primary system. Both systems are tied to a common supply and return ductwork. Outside air is directly supplied to the room.

The primary and backup HVAC systems in the radwaste control room are nonsafety related.

A portion of the 132-in. elevation of the Unit 1 radwaste building is used as a hot tool room. An air conditioner circulates and cools the air for this space along with the normal ventilation system. The cooling coil rejects heated air into the return duct for the radwaste ventilation system.

10.9.3.6 <u>Control Building Ventilation System</u>

10.9.3.6.1 General

The control building is served by HVAC systems. In the general area, outside air is supplied by three 50% capacity fans. The air is filtered and distributed by ductwork in proportion to the equipment and lighting loads in these areas. The exhaust system is split between Units 1 and 2. Three 50% capacity Unit 1 fans and two 100% capacity Unit 2 fans exhaust air to the Units 1 and 2 reactor vent plenums. The following areas are fully air conditioned with direct expansion water-cooled air-conditioning units:

- MCR (section 10.17).
- Computer room.
- Water sampling room.
- Chemical laboratory and health physics area. (Refer to HNP-2-FSAR subsection 9.4.7.)

- Cold lab. (Refer to HNP-2-FSAR subsection 9.4.7.)

Condensing water for the units is from the plant service water (PSW) system. The Shift Supervisor's area air-conditioning unit is an air-cooled system.

A nonessential chilled water system located in the control building provides cooling water to either a nonessential air handling unit or cooling coil located in the following areas:

- LPCI inverter room.
- Vital AC rooms (HNP-1 and HNP-2).
- RPS MG set rooms (HNP-1 and HNP-2).

The battery rooms have exhaust fans and heaters. The cable spreading room has a separate ventilation system.

10.9.3.6.2 MCR Air Conditioning

(Refer to section 9.4 of the HNP-2-FSAR.)

The air-conditioning system for the MCR is completely independent from other air-conditioning systems and consists of three 50% capacity air-conditioning units complete with fresh air supply ductwork, two emergency filters, conditioned air supply ductwork, automatic controls, and air-handling units. Electric heaters are provided for air-handling units 1Z41-B003A and 1Z41-B003B.

10.9.3.6.3 Computer Room Air Conditioning

The computer room is air conditioned by three packaged-type air-conditioning units. The makeup air for ventilation is taken from the control building ventilation system.

10.9.3.6.4 Water Sampling Room Air Conditioning

The water sampling room is air conditioned by two packaged-type air-conditioning units. The makeup air for ventilation is taken from the control building ventilation system.

10.9.3.6.5 Shift Supervisor's Area

(Refer to HNP-2-FSAR paragraph 9.4.7.2.7.)

10.9.3.6.6 LPCI Inverter Room

(Refer to HNP-2-FSAR paragraphs 9.4.7.2.9 and 9.4.7.3.3.)

10.9.3.6.7 Battery Rooms

A 100% capacity exhaust fan is provided for Division I battery rooms [reactor protection system (RPS) battery unit 1A, RPS battery unit 2A, unit 1 vital AC battery, and station battery 1A]; a separate 100% capacity exhaust fan is provided for Division II battery rooms (RPS battery unit 1B, RPS battery unit 2B, unit 2 vital AC battery, and station battery 1B). The two exhaust fans are independent of each other. These fans operate in the event of a loss-of-offsite power when normal ventilation is not available. They may also be operated as required by operations personnel. These fans also prevent the accumulation of hydrogen concentrations in excess of 4% by volume.

Station battery rooms 1A and 1B are each provided with an electric unit heater. The unit-heater system is designed to keep the battery rooms at a minimum temperature of 77°F to assure that the full capacity of the batteries can be discharged on demand. A hydrogen analyzer with monitor is also provided to detect a hazardous buildup of hydrogen in the battery rooms due to ventilation interruption. The hydrogen detection system is interlocked with the heating unit to disable heater startup or trip the heater upon high hydrogen concentration.

10.9.3.6.8 Cable Spreading Room

The cable spreading room is ventilated with a separate ventilating system. The air is recirculated to prevent low temperatures in the ventilated area. The controls for this system are interconnected with the CO_2 fire protection system. The cable spreading room can be isolated by fire dampers in case of fire and can be filled with CO_2.

For further description see HNP-2-FSAR paragraph 9.4.7.2.5.

10.9.3.6.9 HNP-1 Vital AC Room

The HNP-1 vital AC room HVAC system operates identically to the HNP-2 vital AC room HVAC system. For a system description, refer to HNP-2-FSAR paragraph 9.4.7.2.10.

10.9.3.6.10 RPS MG Set Room

The HNP-1 and HNP-2 RPS MG set rooms are cooled by a cooling coil module mounted in the outside air supply duct to the rooms. For a system description, refer to HNP-2-FSAR paragraph 9.4.7.2.11.

10.9.3.6.11 Control Building Chilled Water System

For a description of the control building chilled water system, refer to HNP-2-FSAR paragraph 9.4.7.2.12.

10.9.3.7 Technical Support Center Ventilation System

For a description of the technical support center ventilation system, refer to HNP-2-FSAR subsection 9.4.9.

10.9.3.8 River Intake Structure HVAC System

For a description of the river intake structure HVAC system, refer to HNP-2-FSAR subsection 9.4.10.

10.10 MAKEUP WATER TREATMENT SYSTEM

See HNP-2-FSAR subsection 9.2.3.

10.11 INSTRUMENT AND SERVICE AIR SYSTEM

10.11.1 POWER GENERATION OBJECTIVES

The instrument and service air system provides air of suitable quality and pressure to supply the necessary air requirements for plant operation and maintenance. Instrument air for components within the drywell is provided by the drywell pneumatic system and is discussed in section 10.19.

10.11.2 POWER GENERATION DESIGN BASES

A. The instrument air is a continuous supply of filtered, dry, and oil-free compressed air.

B. Service air is oil-free compressed air, restricted during an emergency so that essential instrument air supply is not impaired.

C. A separate high-volume, low-pressure air system is provided for the fuel pool cooling and cleanup system filter-demineralizer and reactor water cleanup system filter-demineralizer backwashing.

D. The service air system provides a source of high-volume, oil-free, high-pressure service air to an air-surge tank for the condensate polishing filter-demineralizer backwashing operation.

E. Air receiver storage capacity is adequate to supply vital instrumentation with air for a minimum period of 10 min in case of compressor failure.

F. Standby onsite diesel generator power supply can be manually provided for either compressor 1A or 1B upon loss of power from the normal distribution system.

G. Check valves are installed at interfaces with radioactive systems to prevent contamination of instrument air system due to back leakage.

10.11.3 DESCRIPTION

The remainder of the instrument and service air system, exclusive of the drywell pneumatic system, is supplied by three oil-free screw-type compressors, as shown on drawing no. H-11039. Two of these air compressors have a capacity of 500 sf^3/min and one has a capacity of 700 sf^3/min. During normal operation, the one 700-sf^3/min air compressor, 1C, supplies all instrument air and high pressure service air requirements outside of the drywell, with one of the two 500-sf^3/min compressors, 1A or 1B, on automatic standby and the other in backup mode requiring operator action for energization. Each screw-type air compressor has within its package an intake filter, intercooler, aftercooler, blowoff cooler, moisture separators, silencers, automatic load controls, instrumentation, and a control oil and drivetrain lubrication system with oil reservoir, pump, filter, and cooler. External to its package, each compressor has an aftercooler, moisture separator, dryer, receiver, valves, instrumentation, and associated piping. All compressor water jackets and coolers, as well as the external aftercoolers, are cooled by demineralized water in a closed loop that rejects its heat to a fan-cooled heat exchanger. Closed cooling water flow is maintained by two 100% capacity pumps.

The three air receivers discharge into a common manifold that feeds the instrument and service air system. As shown on drawing no. H-11641, the service air/instrument air interface is at the inlet isolation valves for the two 100% capacity prefilters connected in parallel upstream of the dryer. Instrument air passes through the dryer, which removes moisture to a dewpoint of -40°F, and one of two 100% capacity afterfilters connected in parallel downstream of the dryer, which removes 98% of particles ≥ 1.0 mm and all particles > 3 mm, before distribution throughout the plant. The service air system distributes air throughout the plant for services not requiring filtered air. Controls are provided to prevent use of service or nonessential instrument air when supply air pressure decreases to a preset pressure.

A low-pressure air blower supplies large volumes of 18-psi pressure air to the fuel pool cooling and cleanup system filter-demineralizer and reactor water cleanup system filter-demineralizer for backwashing operations.

The condensate polishing system utilizes a large volume of service air as a means to air-surge backwash the demineralizer vessels. In this operation, an air surge tank is used to store service air for use during the backwash operation. The air surge backwash technique makes use of a short-duration, high-velocity, burst of high-pressure service air which drives water to backwash the vessel elements.

The air receiver capacity is adequate to supply instrument air to vital components for a period of ≥ 10 min in the event the air compressors fail. Because compressed air is not essential for safe shutdown of the plant, the air compressors do not switch automatically to operation from the power supplied by the diesel generators following loss of normal power. However, either station service air compressor 1A or 1B has the capability of being operated from the diesel generator system. Vital components, such as the main steam isolation valves, have, in addition, air accumulators for reliable operation with compressor failure.

All gas-motivated valves in the reactor protection system, primary containment isolation system, and engineered safeguard systems fail in the safest position, as determined by the system function, upon loss of the motive gas. As listed in table 10.11-1, certain valves are required to be operable following the initial transients associated with the design basis accident (DBA). Operation of these valves is necessary to mitigate the consequences of a DBA or to ensure prompt detection and isolation of emergency core cooling system (ECCS) suction pipe leaks.

Items 1 through 4, 7 through 16, and 20 through 23 in table 10.11-1 are served by the noninterruptible service parts of the reactor building instrument air system (drawing no. H-16239, sheets 1-9). Items 5 and 6 are served by the nitrogen inerting system itself. Items 18 and 19 are served by the drywell pneumatic system described in section 10.19.

Items 13, 18, and 19 in table 10.11-1 have individual air accumulators described in sections 4.4 and 4.6. A continued air supply after an accident is not required for these valves.

The reactor building instrument air system also employs separate air accumulators for the individual valve or groups of valves it serves (table 10.11-1). Each accumulator is sized for a minimum of five evolutions of the valve(s) served except for the accumulators for item 19 which are sized for a minimum of two evolutions of the valves served. Where two valves are in series with no branches or equipment interposed and the failure of one valve's air supply will close the line, both valves are served by a single air receiver. In these cases, a redundant line is provided with its valves served by another single receiver. Valves T46-F005, T48-F318, T48-F326, T48-F081, T48-F082, T48-F319, and T48-F320 are also served by two air accumulators which are served by redundant lines from single air receivers.

The service air system supplying pressure to the transfer canal transition piece vertical seals, located on the refueling floor, is equipped with an accumulator sized to provide the seals with rated-air pressure for 24 h upon loss of normal compressor flow. This 24-h design requirement is based on normal experienced air seepage through the bladders and connectors with no other abnormal leakage. After these 24 h, the operator will have an additional 12 h at the normal air leakage rate to either restore the compressors or connect an auxiliary nitrogen bottle before seal integrity is lost.

The reactor building instrument air system employs the nitrogen inerting system as a backup source of motive gas for the noninterruptible services. Seismic Category I piping is used in the noninterruptible services. The reactor building instrument air system piping was designed and installed in accordance with the USA Standard Code for Pressure Piping (USAS B31.1.0). The nitrogen inerting system piping is USAS B31.7. The accumulators are designed and built in accordance with American Society of Mechanical Engineers (ASME) Section III, Class 2.

The entry of contaminants into the instrument air system is minimized by employing oil-free compressors, moisture separators, an air dryer, and particulate filters. Drawing nos. H-11039 and H-11641 illustrate the arrangement of these components within the system. The reactor building instrument air system (drawing no. H-16239, sheets 1-9) is designed for 150 psig and 150°F. Relief valves prevent this system pressure from exceeding 125 psig while the maximum ambient temperature is $<$ 150°F in any space served by the reactor building instrument air system.

By employing the above described individualized air accumulators, the nitrogen inerting system as a backup, and by minimizing the accumulators to valve operator distances, the instrument air system compressors may be lost without interrupting the motive gas supply to the valves. To aid in the rapid location of the air leak, the reactor building instrument air system employs flow and pressure transmitters with alarms in the main control room. Each branch of the main headers is equipped with these instruments. All noninterruptible and interruptible services are connected to the branches downstream of these instruments.

The post-erection cleaning consisted of a series of blowdowns from the system normal pressure with the first blowdown point as near each compressor as practicable. The blowdown point progressed away from the compressors as determined by the absence of oil, moisture, and particles from the "pillowcase" over the pipe end. The cleaning media was the oil-free air supplied by each compressor.

The instrument air and service air system was pneumatically tested for leaks following post-erection cleaning per USAS B.31.1.0, Section 137. "Soapbubble" testing was used on joints, fittings, and welds where feasible. Observable leaks were repaired by joint tightening or weld repair.

The following vessels contain gas under pressure and interface with the service and instrument air system:

A. Air receivers are located inside the control building compressor room and are separated from safety-related equipment. The design pressure is 125 psig, and the nominal pressure is 100 psig. The receivers are manufactured and tested in compliance with the ASME Code for Unfired Pressure Vessels, Section VIII. Safety valves are set at 125 psi. The air compressor receivers are designed to comply with Occupational Safety and Health Administration (OSHA) 29 CFR 1910, Subpart M - Hazardous Materials, Section 1910.169.

B. One air receiver is located in the recombiner building, and one is located in the waste gas treatment building. These receivers are designed for a pressure of 125 psig. The nominal pressure is 100 psig. The receivers are manufactured and tested in compliance with the ASME Code for Unfired Pressure Vessels, Section VIII. Safety valves are set at 125 psi. The receivers are designed to comply with OSHA 29 CFR 1910, Subpart M - Hazardous Materials, Section 1910.169.

C. One air receiver (P51-A002) is located on the refueling floor at el 228 ft 0 in. This receiver is designed for a pressure of 200 psig. The nominal pressure is 100 psig at 100°F with the safety relief valve set at 125 psig. This receiver is manufactured and tested in compliance with ASME Boiler and Pressure Vessel Code for Unfired Pressure Vessels, Section VIII. This receiver interfaces with the service air system only.

The only vessels that contain gas under pressure which could affect plant shutdown or redundant safety-related equipment are the air receivers in the control building and the air accumulators in the containment and reactor buildings.

A. As stated in item A above, the air receivers located inside the control building compressor room are separated from safety-related equipment. Since they are located adjacent to the station battery IA room, the possibility of failure was evaluated.

   The normal operating temperature is ~ 100°F, far above the NDTT of carbon steel. Thus, no mechanism for vessel rupture exists, and only a line break is considered. At 125 psig and a maximum temperature of 125°F, the total internal energy that could be released is 5×10^6 ft-lb.

   Postulating a complete break of the 8-in. line at the nozzle location 135 in. above the base flange, the maximum thrust at the nozzle is 11,400 lb at a pressure of 125 psig.

The critical section of the base, occurring through the center of the holes at 4.5 in. above the base flange, would be subjected to a moment of 1.49×10^6 in.-lb. The resulting bending stress would be 25,000 psi. This does not exceed the ultimate material allowable stress of 70,000 psi. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile.

B. There are 41 accumulators in the instrument air and drywell pneumatic systems, both in the reactor building and in the drywell. The operating pressure of the accumulators using as a motive gas source the instrument air system is 100 psig, while the operating pressure of those using the drywell pneumatic system is 125 psig. Both systems employ the nitrogen inerting system as a backup source of motive gas. The operating pressure of the system is 140 psig. Only under the improbable loss of all compressors or a pipe break would this pressure be experienced.

The accumulators are designed as Seismic Class 1 vessels, having a design pressure of 150 psig. In addition, the accumulators are designed for a 70-psig external pressure to accommodate pressure buildup in the drywell. Design temperature is 150°F, and the accumulators are 18 in. in diameter with a 3/16-in.-thick shell. The material is ASME SA-240 304 stainless steel. The water volume is 5.5 ft^3. The accumulators are designed, manufactured, and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 2, and hydrotested at 225 psig. The accumulators, as a part of the integral system, are designed to comply with the OSHA CFR 1910, Subpart M - Compressed Gas and Compressed Air Equipment, Section 1910.169.

Since the accumulators are constructed of stainless steel, no possibility of brittle fracture is foreseen. Stress corrosion cracking is not considered a possibility, because the accumulators are not subjected to a salt environment nor exposed to other corrosive fluids. Therefore, no mechanism for vessel rupture exists.

The bursting pressure of the accumulators, based on a minimum ultimate strength of the material, is 1460 psig. The calculated burst pressure of these accumulators is 10.4 times the maximum operating pressure, assumed to be 140 psig. At a maximum temperature of 125°F, the total internal energy that could be released is 2.1×10^5 ft-lb.

Postulating a separation of the largest line (1 in.) entering the accumulator, a thrust of 181 lb would result, assuming a pressure of 140 psig. This force is a much smaller load than the strength of the holddown bolts. The force needed to fail one bolt is 15,600 lb. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile.

C. Since P51-A002 is located on the refueling floor, the possibility of failure must be evaluated. Normal operating temperature is far above the NDTT of carbon steel; thus, no mechanism for vessel rupture exists, and only a line break is considered. At 125 psig and a maximum temperature of 100°F, the total internal energy that could be released is 43,400 ft-lb. Postulating a complete break of the 2-in. line at the nozzle connection, the maximum thrust is 500 lb. at a pressure of 125 psig. This thrust generates a combined shear-tension load of < 5% of the anchor bolt allowables. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile. The accumulator tank has been mounted seismically to ensure that it cannot damage any safety systems in the area. Since it does not perform a safety function itself, it is not required to function after a seismic event. However, the supply piping to the tank and the discharge piping to the seals have been analyzed and installed to meet Seismic II/I criteria.

D. There are 2 noninterruptible instrument air accumulators for the Hardened Containment Vent System (HCVS). P52-A027 A and B, which are located in the reactor building on El. 185' working floor north, as shown on drawing no. H-16029. The design and normal operating pressures for the accumulators are 150 psig and 100 psig, respectively. The design and normal operating temperatures are 150°F and 100°F respectively. The accumulators employ nitrogen as a backup source of motive gas. The nitrogen system provides gaseous nitrogen at a maximum pressure of 125 psig.

   The accumulators are constructed as Seismic Category I vessels and in accordance with the ASME Code, Section III, Division I, 2001 including 2003 Addenda, Subsection NC and NF. The accumulators are constructed of Type F-304L stainless steel.

   Since the accumulators are constructed of stainless steel, no possibility of brittle fracture is foreseen, nor is stress corrosion cracking considered a possibility because the accumulators are not subjected to a salt environment nor exposed to the other fluids; therefore, no mechanism for vessel rupture exists.

It is concluded that no protection beyond the existing fasteners and supports is required to protect against the above postulated failures of either the air receivers in the control building, the accumulators in the containment and reactor building, and the air receiver on the refueling floor.

10.11.4 INSPECTION AND TESTING

Preoperational inspection and testing was performed on each component during installation.

The instrument and service air system operates continuously and is observed and maintained during normal operation.

TABLE 10.11-1

GAS-OPERATED VALVES

Item No.	MPL No.	Service
1	T45-F001 through F007	Leak detection - ECCS suction
2	E51-F003	Reactor core isolation cooling torus suction
3	E41-F051	High-pressure coolant injection torus suction
4	T48-F310, F311	Reactor building to torus vacuum breaker
5	T48-F113, F114, F321, F322	Drywell N_2 makeup
6	T48-F115, F116, F325, F327	Torus N_2 makeup
7	E21-F019A, B	Core spray system torus suction
8	P41-F066, F067	Service water to reactor building
9	E11-F065A, B, C, D	Residual heat removal system torus suction
10	(Note 1)	
11	P33-F004, F006, F012, F014	$H_2/0_2$ analysis system - drywell
12	P33-F007, F015	$H_2/0_2$ analysis system - torus
13	B21-F028A, B, C, D	Main steam line isolation
14	T46-F001A, F001B, F002A, F002B	Standby gas treatment system
15	P33-F003, F011	$H_2/0_2$ analysis system - drywell
16	P33-F002, F010	H_2/O_2 analysis system - drywell
17	(Note 1)	
18	B21-F022A, B, C, D	Main steam line isolation
19	B21-F013A, B, C, D, F, H, J	Main steam line relief valves
20	T48-F318 and F326	Primary containment purge outlet isolation
21	T48-F081 and F082	Torus hardened vent
22	T46-F005	Standby gas treatment system discharge isolation
23	T48-F319 and F320	Primary containment drywell isolation

NOTE:

1. Items 10 and 17 were changed to solenoid valves.

10.12 POTABLE AND SANITARY WATER SYSTEM

See HNP-2-FSAR subsection 9.2.4.

10.13 PLANT EQUIPMENT AND FLOOR DRAINAGE SYSTEMS

10.13.1 POWER GENERATION OBJECTIVE

The power generation objective of the plant equipment and floor drainage systems is to collect and remove waste liquids from their points of origin and carry them to a suitable disposal area.

10.13.2 POWER GENERATION DESIGN BASES

Liquid wastes are classified in accordance with radioactive contamination potentials, conductivity levels, and chemical contents.

Potentially radioactive wastes are collected separately from the nonradioactive wastes for sampling and analyses prior to disposal in accordance with NRC regulation 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

Drain line penetrations through containment barriers are designed to maintain containment during normal operations and design basis accidents.

10.13.3 DESCRIPTION

The plant equipment and floor drainage systems handle both radioactive and nonradioactive waste. In general, wastes are collected in the building sumps and pumped to the radwaste system for determination of radioactivity prior to cleanup, reuse, or discharge.

10.13.3.1 Radioactive Equipment Drainage System

A. Reactor Building

Reactor containment equipment wastes are collected in two separate systems. The drywell equipment drains sump system collects all equipment drains located in the primary containment. The reactor building equipment drain sump system handles drainage from equipment drains located in the secondary containment. Equipment wastes are collected in closed piping and discharged to an equipment drain sump. Pumps are provided to transfer these wastes from the sumps to the radwaste system. Containment is provided in transferring waste from the sumps to the radwaste system by maintaining a minimum water level in the sump which seals the pump suction lines. To prevent blowout of water seals, the drywell equipment drain discharge line penetrating the primary containment has two isolation valves which close upon high drywell pressure signal or low reactor water level (level 3). Radiation sensors (which upon sensing high radiation, prevent the pumps from running) are provided on the drywell equipment drain sump discharge line.

B. Turbine Building

The turbine building radioactive equipment drainage begins with drains at all items of equipment that require draining, collects in branch lines, empties into main waste lines, and discharges into the equipment drain sump located below the basement level. Sump pumps are provided to pump the discharge from the turbine building to the radwaste system.

C. Radwaste Building

The radwaste building radioactive equipment drainage begins with drains at all items of equipment, collects in branch lines, and empties into main waste lines to a collecting sump. Sump pumps are provided to pump the discharge from the radwaste building to the radwaste system.

D. Technical Support Center

The technical support center carbon filter drains into a collection sump located in the technical support center mechanical equipment room. No sump pumps are provided to discharge from this sump.

10.13.3.2 Radioactive Floor Drainage System

With minor exceptions, all floor drains for the reactor building, turbine building, control building, and radwaste building are collected in branch lines, empty into main waste lines, and discharge into floor drain sumps located in the basements or lowest level of the buildings. Sump pumps transfer these wastes from the buildings to the radwaste system. The drywell floor drain sump discharge line is provided with radiation sensors that prevent the pumps from running on high radiation.

10.13.3.3 Nonradioactive Water Drainage System

Roof drains from the reactor building, radwaste building, turbine building, control building, and service building are collected and discharged to the storm drain system.

Some floor drains in the control building are collected in branch lines and discharged into the nonradioactive waste drainsump located below the basement level and transfered to the radwaste system. Floor drains in the technical support center are discharged to the storm drain system.

10.13.4 INSPECTION AND TESTING

Portions of the plant equipment and floor drainage systems were hydrostatically tested during erection to prove the integrity of the system.

Other portions of the plant equipment and floor drainage systems are proved operable by use during normal plant operation.

10.14 PROCESS SAMPLING SYSTEMS

10.14.1 POWER GENERATION OBJECTIVE

The power generation objective of the process sampling systems is to monitor the operational performance of plant equipment and provide information for making operational decisions.

10.14.2 POWER GENERATION DESIGN BASES

The process sampling systems are designed to:

A. Obtain representative samples in forms which can be used in radiochemical laboratory analyses for determination of plant equipment effectiveness.

B. Minimize the radiation effects at the sampling stations.

10.14.3 DESCRIPTION

Samples are taken from various streams and locations as indicated in table 10.14-1. Sample points are grouped as much as possible at normally accessible locations, and drains are provided at these locations to limit the risk of contamination. Lines are sized to insure purging and sufficient velocities to obtain representative samples. Samples are taken to the laboratory for appropriate analysis. In addition, continuous automatic monitoring and alarm of undesirable conditions is provided using in-line detectors where necessary.

TABLE 10.14-1 (SHEET 1 OF 3)

PROCESS SAMPLING SYSTEMS

Description	Locations	Purpose
Nuclear Steam Supply System		
Main steam	Main steam line	Carryover quality, H_2 and 0_2
Suppression pool	Suppression pool	Monitor corrosion and activity
Standby liquid control system	Standby liquid control tanks	Borate concentration
Reactor water (Note 1)	Reactor water cleanup system	Monitor reactor water during normal operation
	Recirculation system	Monitor reactor water when cleanup is isolated
Reactor water	Recirculation system	Zinc concentration
	Post accident sampling system	Monitor reactor water during normal or accident conditions
Reactor Water Cleanup Demineralizer System		
Filter demineralizer	Inlet	Reactor water quality
Filter demineralizer	Outlet	Filter efficiency
Condensate System		
Condensate	Condensate pump discharge	Condensate quality and tube leaks
Condensate demineralizer	Outlet	Condensate quality
Reactor Feedwater System		
Feedwater	Halfway in heater train feed piping	Water quality
Feedwater	After last heater	Water quality
Feedwater	GEZIP skid	Zinc concentration
Plant extraction system	Drain discharge to condenser	Water quality

TABLE 10.14-1 (SHEET 2 OF 3)

Description	Locations	Purpose
Makeup		
Cation effluent (secondary)	Outlet	Demineralizer efficiency
Primary cation	Outlets	
Degasifier	Outlet	Process data
Anion effluent (secondary)	Outlet	Demineralizer efficiency
Primary anion	Outlets	
Condensate storage tank	Pump discharge	Water quality
Reactor Building Closed Cooling Water System		
Cooling water	Outlet of each major heat exchanger	Determine location of heat exchanger leaks
Cooling water	Pump discharge	Check corrosion inhibitor concentration
Main Condenser Circulating Water System		
Circulating water	Pump discharge	Determine background
Liquid Radwaste System		
Waste surge tank	Outlet	Process data
Waste collector tank	Pump discharge	Process data
Floor drain collector tank	Pump discharge	Process data
Laundry drain tanks	Pump discharge	Discharge suitability
Waste sample tank	Pump discharge	Discharge suitability
Floor drain sample tank	Pump discharge	Discharge suitability
Radwaste filter-demineralizer	Outlet	Filter efficiency
Special Samples		
Resin sample	Resin transfer line	Test resin mixing

TABLE 10.14-1 (SHEET 3 OF 3)

Description	Locations	Purpose
Spent Fuel Pool Cooling and Demineralizer System		
Fuel pool filter-demineralizer	Inlet	Fuel pool quality
Fuel pool filter-demineralizer	Outlet	Filter efficiency
Plant Off-Gas System		
Air ejector	After air ejectors	Activity release, H_2, O_2, and air leakage
Off-gas filter	Inlet and outlet	Determine filter efficiency
Stack sample	Main stack	Particulate and iodine release
Ventilation	Fan discharge	Activity release

NOTE:

1. For a more detailed discussion of process sampling, see HNP-2-FSAR subsection 7.6.11.

10.15 PLANT COMMUNICATION SYSTEM

See HNP-2-FSAR subsection 9.5.2.

10.16 PLANT LIGHTING SYSTEM

See HNP-2-FSAR subsection 9.5.3.

10.17 MAIN CONTROL ROOM ENVIRONMENTAL CONTROL SYSTEM

See HNP-2-FSAR section 6.4.

10.18 EQUIPMENT AREA COOLING SYSTEM

10.18.1 POWER GENERATION OBJECTIVE

The power generation objective of the equipment area cooling system is to maintain the environment of the residual heat removal (RHR), core spray (CS), reactor core isolation cooling (RCIC), high-pressure coolant injection (HPCI), and control rod drive (CRD) pump rooms at temperatures within the design limits during the periods particular equipment is in operation or normal operating temperature is exceeded.

10.18.2 POWER GENERATION DESIGN BASIS

The equipment area cooling system is designed to deliver cooling air as required to the RHR, CS, RCIC, HPCI, and the CRD pump rooms to maintain room temperatures within the design limit.

10.18.3 SAFETY OBJECTIVE

The safety objective of the equipment area cooling system is to maintain the environment for the electrical components of the emergency core cooling system (ECCS) at temperatures within their maximum allowable operating limits.

10.18.4 SAFETY DESIGN BASES

A. The equipment area cooling system is designed to deliver cooling air as required to the environment of the ECCS electrical components in the event of an accident or when normal operating temperature is exceeded.

B. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

10.18.5 DESCRIPTION

The portion of the system serving the ECCS is designed in accordance with Seismic Category I criteria. The equipment area cooling system (drawing no. H-16023) consists of fan coil unit coolers and the instrumentation. The coolers, with their associated instrumentation, control the environmental temperature in the RHR and CS pump rooms, the RCIC pump room, the HPCI pump room, and the CRD pump room. The equipment area cooling system serves as the heat sink for the equipment in those areas.

The starting of the RHR pumps, CS pumps, HPCI turbine or RCIC turbine, or high temperature automatically starts the fan coil units located in the respective room. The CRD pump room fan coil units are automatically started on a high-temperature signal.

During these conditions, both fan coil units are started automatically. Upon verification that both fan coil units are operating, any one fan coil unit can be selected and placed in standby condition while the other fan coil unit continues to operate. If the operating unit fails, the standby unit is started automatically and an alarm is actuated in the main control room.

The fan coil units are designed to maintain the environmental temperature in the respective rooms < 148°F when the pumps are in operation. The CRD pump room fan coil units are sized to maintain the room temperature < 104°F with 90°F cooling water. CRD pump room cooling is not a safety design function.

Upon loss of offsite ac power, all equipment area fan coil units operate from emergency buses.

10.18.6 SAFETY EVALUATION

The system is designed with sufficient redundancy so that no single active system component failure can prevent the equipment area cooling system from achieving its safety objective.

10.18.7 INSPECTION AND TESTING

The energy removal capability of the fan coil unit coolers of the equipment area cooling system can be evaluated when any of the HPCI, RCIC, RHR, CS, or CRD systems are operating, and by measuring the compartment air temperatures where the equipment is located.

10.19 DRYWELL PNEUMATIC SYSTEM

10.19.1 POWER GENERATION OBJECTIVE

The drywell pneumatic system provides gas of suitable quality and pressure to supply the equipment which requires motive gas and is located within the drywell.

10.19.2 POWER GENERATION DESIGN BASES

A. The drywell pneumatic system supplies, at the minimum 90 psig, clean, dry, oil-free gas to the equipment which requires motive gas and is located within the drywell.

B. Gas receiver storage capacity is adequate to supply equipment with gas for a minimum period of 10 min.

10.19.3 SAFETY OBJECTIVE

The safety objective of the drywell pneumatic system is to provide gas to essential equipment which requires motive gas and is located within the drywell.

10.19.4 SAFETY DESIGN BASES

A. Provide pneumatic supply to the safety relief valves (SRVs) to ensure the short-term capability to actuate these valves when required.

B. Provide pneumatic supply to the SRVs to ensure the long-term capability to actuate these valves when required.

C. Protect against the inadvertent actuation of the SRVs and main steam isolation valves (MSIVs) due to excess pneumatic supply pressure.

D. Provide containment isolation capability.

E. Protect against the depletion of the nitrogen supply and the overpressurization of the drywell due to the rupture of the pneumatic header in the drywell.

10.19.5 DESCRIPTION

During normal operation, motive gas requirements are satisfied by the makeup nitrogen supply from the nitrogen inerting system (T48). The nitrogen is piped from the nitrogen supply through particulate filters and pressure regulators and ultimately distributed to the equipment in the drywell by two separate headers (drawing nos. H-16286 and H-16299).

The supply header pressure regulators (F103A and F103B) reduce the gas pressure to ~ 108 psig in order to maintain the pneumatic header pressure in the drywell above the minimum allowable 90 psig.

Vital components, such as the MSIVs and SRVs, have gas accumulators to ensure reliable operation in case of interruption of the gas supply. In order to utilize receiver 1P70-A001 with the nitrogen supply, the internals of check valve 1P70-F016 must be removed and valve 1P70-F015 locked closed.

A backup supply of nitrogen to the drywell is provided through three interchangeable nitrogen bottles and a manifold system at one of two emergency nitrogen hookup stations. This alternate mode of operation is described in paragraph 10.19.7.6.

The original plant design utilized redundant compressors to take suction from the drywell atmosphere and return compressed gas to the drywell equipment. These compressors are now out of service. The compressors have been isolated and the system malfunction alarm in the main control room (MCR) has been disconnected. The containment isolation valves on the compressor suction line remain operable and in place, although the suction line has been capped off.

10.19.6 INSTRUMENTATION APPLICATION

The majority of the control instrumentation for the drywell pneumatic system is located on the local panel, except for the alarms which are located in the MCR. The remote manual switches for the makeup nitrogen supply valves and containment isolation valves are also located in the MCR.

When the drywell pneumatic compressors are in service, two pressure switches located on the receiver maintain a constant pressure in the receiver. Other instrumentation consisting of pressure switches, level switches, pressure indicators, and differential pressure indicators is provided to ensure the proper function of the system.

Pressure control valves are installed after the drywell pneumatic filters for the purpose of reducing the supply gas pressure in order to meet the component requirement.

10.19.7 SAFETY EVALUATION

Except for the main steam SRVs, pneumatic-operated devices contained in the drywell are designed for the fail-safe mode and do not require continuous gas supply under emergency or abnormal conditions.

10.19.7.1 Short-Term SRV Pneumatic Supply

Short-term SRV pneumatic supply requirements are satisfied by the individual accumulators provided for each automatic depressurization system (ADS) valve and installed for each non-ADS SRV. Each ADS accumulator is sized to ensure two SRV actuations at 70% drywell design pressure within the first half hour. This elevated drywell pressure is the result of the largest primary system break for which the ADS is required. For smaller breaks within the drywell or for breaks outside the drywell, the accumulator availability will be extended considerably. For events not involving breaks within the drywell, accumulator capacity is sufficient to ensure multiple SRV actuations for > 2 h.

The ADS is required for events where, following an isolation, the reactor remains at high pressure, and the high-pressure makeup systems [e.g., high-pressure coolant injection (HPCI)] are not available to maintain vessel level. Specifically, for events resulting in reactor isolation for small-break loss-of-coolant accidents (LOCAs) where break flow is insufficient to depressurize the reactor and HPCI is not available, the ADS valves must act to depressurize the vessel so that the low-pressure injection (LPCI) mode of the residual heat removal system and the core spray (CS) system can be used to restore and maintain vessel level.

There are seven ADS valves, each provided with an accumulator. Analysis has shown that a maximum of four ADS valves could become pneumatically or electrically disabled due to a pipe break in the drywell. Therefore, a minimum of three ADS valves will be available during the first half hour to depressurize the vessel if HPCI is not available. Based upon plant-specific calculations which were completed using the methodology developed for the Boiling Water Reactor Owners Group Emergency Procedure Guidelines (BWROG EPGs), the minimum number of SRVs required for rapid depressurization is three. In addition, for breaks less than one SRV port area, at least three and in some cases four non-ADS SRVs will be available to support the low-low set (LLS) function. These valves can be manually actuated to help depressurize the vessel.

Soft-seated check valves were installed at the inlet to each ADS valve accumulator, as required by IE Bulletin 80-01, thus ensuring adequate leaktightness of the ADS valve accumulators in case their pneumatic supply is cut off. Pressure switches with alarms installed in the drywell pneumatic system supply headers will generate a low-pressure signal and alert the operator if the ADS accumulators are not being properly charged. A minimum accumulator pressure of 90 psig must be maintained during normal plant operation.

Other short-term pneumatic supply requirements for certain SRVs are stipulated by the LLS relief logic system discussed in section 7.19.

10.19.7.2 Long-Term SRV Pneumatic Supply

Long-term SRV pneumatic supply requirements are satisfied by the modified drywell pneumatic system and the safety-grade compressed nitrogen system. If the vessel is not depressurized within the first half hour after an isolation event (with or without a break in the drywell), at least three SRVs, or an equivalent break size, must be available to depressurize the vessel if required. Also, following certain events, a minimum of one SRV may be required to provide an alternate shutdown cooling path for the vessel. Specifically, this alternate shutdown cooling path is required when the residual heat removal shutdown cooling path is not available.

10.19.7.3 Overpressure Protection Requirements

A pressure switch and alarm (P70-PS-N017) installed in the common pneumatic supply header will alert the operator to the presence of excess pneumatic pressure which could cause inadvertent actuation of the SRVs or MSIVs. A relief valve (P70-F100) provides positive overpressure protection. The high-pressure alarm and relief valve were added as required by IE Bulletin 80-25.

10.19.7.4 Containment Isolation Requirements

The design of the drywell pneumatic system satisfies the requirements of 10 CFR 50, Appendix A, General Design Criterion 56, concerning containment isolation. Two automatic isolation valves are provided for each header in the drywell pneumatic system.

Redundant containment isolation valves for each pneumatic header close automatically when a pipe rupture is sensed in the respective header. This sensing instrumentation is described in paragraph 10.19.7.5. Provisions are included to allow containment leakage testing per 10 CFR 50, Appendix J.

10.19.7.5 Flow Instrumentation

Flow instrumentation is provided to sense a high flow or a rupture of either pneumatic header inside the drywell. The ruptured header will be automatically isolated, thus satisfying containment isolation requirements and ensuring that the liquid nitrogen tank (T48-A001) will not be depleted and that the drywell will not be overpressurized due to an uncontrolled nitrogen flow. A time delay is included in the high-flow isolation logic to ensure that isolation does not occur during normal actuation of air-operated valves in the drywell.

10.19.7.6 Protection Against Postulated Failures

The modified drywell pneumatic system uses two separate pneumatic headers inside the drywell, each supplying one-half of the SRVs (11 total) and other air-operated valves in the drywell. Four ADS valves and two non-ADS SRVs are on one header; the other three ADS valves and two non-ADS SRVs are on the second header. The two headers tie into a common header outside the drywell which is supplied by a safety-grade, single-failure-proof, compressed nitrogen system.

Separation is such that no pipe break, with a break area less than or equal to three SRV port areas, occurring in the drywell can concurrently cause damage to both pneumatic headers. In addition, separation is such that no break described above can disable more than one ADS valve and one non-ADS SRV. Loss of one pneumatic header, one ADS valve, and one non-ADS SRV still leaves a minimum of three SRVs available for depressurization and alternate shutdown cooling.

The drywell pneumatic system and the nitrogen system are not specifically protected from the effects of a pipe break occurring outside the drywell, except at the drywell penetrations. Credit is taken for local operator action to restore this penumatic supply within 2 h, if damaged by a pipe break occurring outside the drywell. This is a time critical operator action as defined in Unit 2 FSAR subsection 15.1.5.

Three interchangeable nitrogen bottles and a manifold system are provided at the emergency nitrogen hookup station (P70-F084) to give the operator the capability to restore pneumatic supply to the drywell in the event that the nitrogen supply from the purge and inerting system becomes unavailable as the result of a fire. The nitrogen bottles and the manifold system are functionally nonsafety related. However, to protect the integrity of other safety-related systems in the area, the bottle rack is a Seismic Category I structure, and a safety-related missile shield is installed above the bottle rack.

The drywell pneumatic system receiver is located in the reactor building northwest corner room at el 87 ft. The design pressure is 150 psig, and the operating pressure is 125 psig. The pressure vessel (receiver) is manufactured and tested in compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Class 2. The safety valve is set at 145 psig. A pressure rise in the receiver caused by any reason, such as fire, is limited to this set pressure. The receiver is designed to comply with Occupational Safety and Health Administration (OSHA) 29 CFR 1910, Subpart M-Hazardous Materials, Section 1910.169.

The normal operating temperature of the drywell pneumatic system receiver is ~ 100°F, far above the nil ductility transition temperature of carbon steel. Thus, no mechanism for vessel rupture exists, and only a line break is considered. At the design pressure of 150 psig and a design temperature of 200°F, the total internal energy that could be released is 2.5×10^6 ft-lb.

The force needed to fail one bolt holding the manhole inspection cover is 75,750 lb. The force exerted on the cover at a pressure of 150 psig is 54,287 lb shared among 16 bolts. Postulating a separation of the largest line entering the receiver, which is a 2-in. line, a thrust of 797 lb results. The critical section of the base would be subjected to a moment of 5.26×10^4 in.-lb. The force exerted would be shared between two of the four holddown bolts. Assuming that only one bolt was subjected to the force exerted, the force would be 2664 lb. The force needed to fail one bolt is 57,750 lb. Thus, neither the tank nor any part of the tank will break loose or become a missile as a result of a pipe failure.

The nozzles are located such that none of them point toward any essential or safety-related equipment. Therefore, jet loads resulting from the rupture of any piping connection would not disable any essential or safety-related equipment.

It is concluded that no protection beyond the existing fasteners and supports is required to protect against the above-postulated failures.

The accumulators are designed as Seismic Category I vessels. The design pressure is 150 psig. In addition, the accumulators are designed for a 70-psig external pressure to accommodate pressure buildup in the drywell. Design temperature is 150°F. The accumulators are 18 in. in diameter with a 3/16-in.-thick shell. The material is ASME SA-240 304 stainless steel. The water volume is 5.5 ft^3. They are designed, manufactured, and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 2, and hydrotested at 225 psig. The accumulators, as a part of the integral system, are designed to comply with OSHA 29 CFR 1910, Subpart M-Compressed Gas and Compressed Air Equipment, Section 1910.169.

Since the accumulators are constructed of stainless steel, no possibility of brittle fracture is foreseen nor is stress corrosion cracking considered a possibility because the accumulators are neither subjected to a salt environment nor exposed to other corrosive fluids. Therefore, no mechanism for vessel rupture exists.

The bursting pressure of the accumulators based upon a minimum ultimate strength of the material is 1460 psig. The calculated burst pressure of these accumulators is 10.4 times the maximum operating pressure which is assumed to be 140 psig. At a maximum temperature of 125°F, the total internal energy that could be released is 2.1×10^5 ft-lb.

Postulating a separation of the largest line entering the accumulator, which is a 1-in. line, a thrust of 181 lb results, assuming a pressure of 140 psig. This force is a much smaller load than the strength of the holddown bolts. The force needed to fail one bolt is 15,600 lb. Thus, the tank will not break loose as a result of pipe failure and will not act as a missile.

10.19.8 INSPECTION AND TESTING

Preoperational inspection and testing was performed for each component during installation.

The drywell pneumatic system operates continuously and is monitored and maintained during normal operation.

Safety relief valve accumulator system leakage will be checked during every refueling outage. Combined leakage from all points (i.e., check valve, solenoid valves, actuator, fittings, etc.) must be less than 4.5 sf^3/h. Repairs will be made to bring the leakage rate within the allowable value prior to plant startup.

10.20 <u>OVERHEAD HANDLING SYSTEMS</u>

10.20.1 POWER GENERATION OBJECTIVES

The reactor and turbine building cranes, major components of the overhead handling system, provide the capability to move major components for refueling operations and maintenance.

10.20.2 POWER GENERATION DESIGN BASES

A. The HNP-1 reactor building crane provides service to both HNP-1 and HNP-2. The HNP-1 reactor building crane is a single-failure-proof crane, meaning that a single failure will not result in the loss of the capability of the system to safely retain its load. The HNP-2 reactor building crane is not a single-failure-proof crane, but it is used under strict administrative control over the refueling floor. Load drop analysis have been performed to determine maximum lifting heights above the floor and load paths to be followed whenever this crane is used over the refueling floor (reference drawing H-10167). The HNP-1 reactor building crane has the capability to handle loads up to 125 tons using the main hook. This capability includes the handling of shield plugs, reactor vessel heads, drywell heads, steam dryers, steam separators, the 360 degree auxiliary work platform, and the spent-fuel cask. (Refer to table 10.20-1 for reactor building crane service information.)

B. The reactor building crane has the capability to move equipment from the grade floor level, for use at the refueling floor level, through a hatch in the refueling floor. This capability includes the handling of the spent-fuel cask, new fuel, motor generator sets, control rod drives, and other heavy components, if required.

C. The reactor building crane main and auxiliary hooks have an electrical interlock system to prevent their potential movement over spent fuel. This interlock may be bypassed, but only under strict administrative controls.

D. The turbine building crane has the capability to handle loads up to 180 tons using the main hook.

E. The turbine building crane has the capability to move equipment along the length and breadth of the turbine deck up to the control room in the HNP-1 turbine building and from grade elevation up to the turbine deck through the service opening.

F. Both the reactor and the turbine building cranes have the capability to perform their required functions in the safest possible manner while maintaining reliability and optimum control.

G. A permanent mast-mounted underwater television camera and associated monitors on the refueling platform bridge assist in the inspection of the vessel internals and general underwater surveillance in the reactor vessel and fuel storage pool.

10.20.3 CODES AND STANDARDS

The reactor building and turbine building overhead cranes comply with the intent of Crane Manufacturers Association of America (CMAA) Specification No. 70 Class A1 (Standby Service), thus meeting the intent of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," Guideline 7. This service class covers cranes used in installations where precise handling of valuable machinery at slow speeds with long idle periods between lifts is required and where capacity loads may be handled for initial installation of machinery or for infrequent maintenance.

The design, fabrication, testing, and maintenance of the reactor head strongback, reactor pressure vessel head carousel / tensioner assembly and the dryer/separator sling assembly meet the intent of NUREG-0612, Guideline 4.

Load testing of the Reactor Head Strongback, Reactor Pressure Vessel Head Carousel/Tensioner Assembly is not required. Dimensional testing, visual inspection, and nondestructive testing of major load-carrying welds and critical areas are performed consistent with ANSI N14.6-1978, with the exception that nondestructive testing is conducted on a 10 year interval.

Both the reactor building overhead crane and the turbine building overhead crane comply with the Occupational Safety and Health Administration (OSHA) Subpart N - Materials Handling and Storage of 29 CFR Part 1910, Section 1910.179, Overhead and Gantry Cranes, insofar as applicable to indoor powerhouse cranes.

The turbine building and reactor building cranes, consisting of structural girders, end beams, trucks, trolley machinery bed and trucks supporting the mechanical traction drive, hoisting machinery, reeving system, and lifting devices, were designed, fabricated, installed, and tested according to the guidelines established in the codes and standards of the following organizations:

- American Gear Manufacturer Association (AGMA), for defining and calculating the gear durability and strength horsepower requirements.

- Anti-Friction Bearing Manufacturers Association (AFBMA), for bearing load limits and expected bearing life calculations.

- Association of Iron and Steel Engineers (AISE), for basic outline of mechanical components such as drum grooving, drive systems, electrical horsepower calculations, and reeving efficiency calculations.

- American Society of Civil Engineers (ASCE), for rules for designing the structure, bolting, and connections, which are not fully covered in CMAA Specification 70.

- American Society for Testing Materials (ASTM), for specifying the grades of material and material testing procedures.

- American Iron and Steel Institute (AISI), for specifying general materials such as shafting and forgings.

- American Welding Society (AWS), D14.01 or D2.0 used for welding procedures.

- CMAA Specification No. 70, for basic parameters and structural, mechanical, and electrical features.

- National Electric Manufacturers Association (NEMA), used to specify electrical equipment such as controls and panels.

- Steel Structures Painting Council (SSPC), for cleaning and painting specifications.

- American National Standards Institute (ANSI), the B30.2.0 safety code for electric overhead bridge cranes.

- National Fire Protection Association (NFPA), for electric safety codes which are also part of OSHA.

- National Electrical Code (NEC), for specifying the wiring, insulation, and fastenings.

- Institute of Electrical and Electronics Engineers (IEEE), for industrial controls and recommended practices.

- Occupational Safety and Health Administration (OSHA), for safety requirements for walkways, guard rails, switchgear, clearances, checkout and testing procedures for maintenance and operation.

- American Society of Mechanical Engineers (ASME), defines nondestructive testing and supplements ASTM and AWS and assists in design of machinery components.

- American Institute of Steel Construction (AISC), for specification of rails and structural methods; covers the details only referenced in the CMAA Specification No. 70.

- Society of Automotive Engineers (SAE), for shafting and machinery fittings not contained in AISI and AISC.

- Local and State codes, such as Southern States Building Code, for loading and impact considerations.

The operating practices, as well as the qualifications and training of personnel who operate or direct the operation of the reactor building and turbine building cranes, conform with the intent of the requirements of Chapter 2-3, Operation - Overhead and Gantry Cranes USAS B 30.2 - 1967 as developed by the American National Standard Safety Code for cranes, derricks, hoists, jacks, and slings.

10.20.4 TURBINE BUILDING OVERHEAD CRANE

All the structural components and machinery of the turbine building crane are designed for a full capacity of 180 tons with a minimum safety factor of 5 against ultimate failure for the load carrying parts and the machinery. The structural components are designed in accordance with Section 70-3 of CMAA Specification No. 70.

The crane runway (supporting structure and rails) which is an integral part of the superstructure of the turbine building is designed in accordance with design methods of applicable codes and standards.

The crane design has provided a safety factor of 5 for mechanical machinery. All lifting devices, slings, and load connections also have a minimum safety factor of 5.

The main hook is a two-pronged sister hook with a bail hole. It is designed with a safety factor of 5 when loaded equally on each prong with a maximum included sling angle of 60 degrees. The rated load may also be handled using the bail hole.

The reeving system consists of two separate ropes attached to an equalizing bar which provides for equal division of the load between the two ropes. With both ropes functioning and equalized, the safety factor of the ropes is 5.0 on a static basis. If one rope should fail, the remaining rope could support the load with a residual safety factor of 2.5 on a static basis.

The turbine building crane consists of electric-powered hoisting machinery attached to a trolley platform to raise and lower loads by wire rope reeving through blocks. The loads are secured to the load block by lifting devices. The structural frame support for the hoisting machinery is the trolley, which moves by tractive power on trucks over rails secured to the top of the two parallel matched crane girders. These are held together with structural end beams. The two end beams are supported by wheeled trucks (two pair on each side) which travel on top of the runway rails. The runway rail is structurally supported by foundations. The crane is designed to be controlled from a cab located at the west end of the bridge or by radio control from the operating floor. However, the radio control equipment has been abandoned in place and is no longer utilized to control the crane.

The design includes safety factors and features, and considers modes of failure as follows:

A. The design rated capacity is 180 tons, and the crane is mechanically designed to a balanced factor of safety in which all components have a minimum safety factor of 5.

B. The reeving system consists of two separate ropes reeved between load and head block and secured to an equalizing bar which provides for equal division of the load between the two ropes. Rigid inspection and checking of the ropes assure dependable service and reliability. The ropes have a safety factor of 5.0 as a minimum.

C. The sister hook with bail hole is forged to ASTM specifications and tested to a 200% design capacity. Each prong and the cored bail hole have a design rated capacity of 180 tons. The conservative safety factor to ultimate is $>$ 5. The load block, reeving rope, head block, drum, gear reducer, couplings, and motor shaft which make up the basic hoisting systems all have a safety factor to ultimate in excess of 5.

D. The hoisting operation is protected by an eddy current braking system and electric holding brakes. The electric brakes are a safety automatic type which set should power fail and are only released during operations when the system is energized. The eddy current regenerative brake system is a control type which prevents overspeed and is used to regulate load lowering speed. The holding brake system stops and holds the rated load. Each brake is sized to excess of 125% full-load motor torque as a minimum.

E. Should hoisting operation continue without operator control, two limit switches are provided, either one will prevent load block from contacting the head block. One limit switch is actuated by drum rotation and the other on mechanical rise of the load block.

F. The trolley and bridge travel have five-step variable speed control on travel speed from start to full design speed to provide for low impact due to acceleration. The trolley and bridge each have a rectified dc magnetic holding brake system which sets should power fail and which must be energized for operation. The bridge motor also has an electric hydraulic foot brake. Brake systems are sized to 50% full-motor torque for trolley and 150% full-motor torque for bridge. The bridge and trolley are provided with track-type limit switches to prevent overtravel in either direction. Movement of heavy loads close to the control room wall by overriding the limit switches is controlled by operational procedures and strict adherence to the established load paths.

G. Thermal overload protection is provided for all electric power circuits. This prevents continuation of motor stalling torque.

The HNP-1 turbine building crane is shared on a limited basis with HNP-2. To prevent hazardous conditions from being created when the crane passes over the control room roof, the following features were incorporated into the design:

A. A reinforced concrete wall around the perimeter of the control room extends above the reinforced concrete control room roof to el 192 ft 0 in. and houses a portion of the control building ventilation and air-conditioning equipment. The ventilation ducts extend above this concrete wall and do not permit clearance through the area below el 194 ft 0 in. The maximum lift of the crane hooks is el 209 ft 0 in. This limited clearance with the crane passing over the control room does not permit transporting a load from the HNP-1 turbine area to the HNP-2 turbine area. To exclude any such possibility, operational procedures forbid moving a load from the HNP-1 turbine area to the HNP-2 turbine area.

B. Although the turbine building is a Category II building, it is designed to prevent failure due to the seismic events described for Category I structures as well as failure due to the tornado criteria.

C. A full-load turbine building crane is installed for each unit; therefore, the need to move a crane from one unit to the other is limited. When such a move is required, an operational procedure describes the precautions and procedure to be followed.

Movement of the portions of the control building ventilation and air-conditioning equipment, located on top of the control room, is controlled by an operational procedure and strictly adheres to established safe load paths.

<u>Performance and Acceptance Testing</u>

The performance and acceptance testing of the turbine building crane system included:

- *Detailed checking of the installed runway and assembled crane.*

- *Performance test with the 180-ton rated load and the 125% test load.*

Preliminary instructions and procedures for operating, servicing, and maintaining the crane were prepared prior to and used during the performance and acceptance testing period. Records of the performance testing and adjustments made to system controls provide the basis of detailed operating procedures, instructions for handling specific loads, servicing requirements, and the maintenance program.

Following overhauls and major repairs to components of the crane, a complete performance and 125% proof test is conducted to verify and prove the integrity of the crane.

10.20.5 REACTOR BUILDING OVERHEAD CRANE

All the structural components and machinery of the reactor building crane are designed for a full capacity of 125 tons plus design basis earthquake (DBE) with a minimum safety factor of 5 against ultimate failure for the load carrying parts and the machinery. The structural components, such as girders, trolley drums, and drum catcher, have a design safety factor of 2.5 against yield. With the hoisting mechanism, all load carrying parts except structural members and hoisting ropes are designed so that the calculated static stress in the material, based on rated load, does not exceed 20% of the assumed average ultimate strength of the material. The gears are designed per AGMA Standard, and bearing life is designed per CMAA Specification No. 70. The overall rope static safety factor is $>$ 10.0 at rated load, which gives a safety factor of more than 5.0 per rope. Motor torque is limited to 175% of that for rated loads.

The crane runway, supporting structure, and rails, which are integral parts of the superstructure of the reactor building, are designed by methods described in chapter 12. Loading combinations and stress limits are given in paragraph 12.4.2.4. Governing codes are listed in subsection 12.4.4.

The reactor building crane consists of electric-powered hoisting machinery attached to the trolley platform to raise and lower loads by wire rope reeving through blocks. The loads are secured to the load block by lifting devices. The structural frame support for the hoisting machinery is the trolley which moves by tractive power on trucks over rails secured to the top of the two parallel matched crane girders. These are held together with structural end beams. These two end beams are supported by wheeled trucks (two pair each side) which travel on top of the runway rails. The runway rail is structurally supported by foundations. The crane is designed to be controlled from a cab located at the east end of the bridge or by radio control from the operating floor. However, the radio control equipment has been abandoned in place and is no longer utilized to control the crane.

Crane Design Features

The design of the reactor building crane includes safety factors and features and considers modes of failure as follows:

A. The design-rated capacity is 125 tons, and the crane is mechanically designed to a balanced factor of safety in which all components have a minimum safety factor which exceeds 5.

B. Two balanced, 16-part reeving systems provide redundancy. The arrangement consists of two separate load-sharing wire cables reeved side-by-side through the upper and lower block sheaves. (See figures 10.20-1 and 10.20-2.) The initial cables are supplied by the U.S. Steel Corporation and have a published breaking strength of 175,800 lb. The static load on each cable at rated capacity equals live loads (125 tons) plus bottom block weight (5 tons) divided by the total parts of the cable (16 parts), which equals ~ 16,300 lb. Each cable passes through a paired equalizer unit that adjusts for unequal cable length and is used as a load transfer safety system. This energy absorbing device eliminates sudden load displacement and shock to the crane system in the unlikely event of a cable break. The factor of safety is halved when a cable breaks, but no swinging action occurs because the cable is reeved to each side of the upper and bottom blocks. A redundant equalizer shaft consists of a solid rod within a hollow tube; either shaft can support the full load in case of a failure of the other. (See figure 10.20-3.)

C. The main functions of the equalizer system are to continually adjust the hook load such that any load under normal operation is shared equally by the redundant reeving system or to transfer the shock of a cable break in an acceptable, safe dynamic fashion to the remaining cable. If there is an exaggerated displacement of the equalizer assembly, caused by a cable break, either of two proximity limit switches are activated. The equalizer system of the main hoist utilizes vane-type limit switches which stop the hoisting motion should the hoisting rope lengths need adjustment. The hoisting motion also stops if one set of reeving fails so that the broken cable can be removed before it becomes entangled with the other reeving system. This equipment protection mechanism initiates the emergency braking system to stop the hoisting motion. Prior to making a lift, a visual inspection of this system is made so that an unnecessary power shutoff does not occur. If the equalizer bar needs to be adjusted during a lift, the load is lowered and the adjustment is made at the cable drum anchors. If the equalizer bar needs to be adjusted during a lift, the load is lowered and the adjustment is made at the cable drum anchors. If the equalizer bar reaches the limits of its travel, which should occur only if one of the cables has already failed, the load can be safety lowered with the remaining cable and a new cable installed.

Rigid inspection and checking of the cable assures dependable service and reliability. The cable reeving from the drum to the hook has a mechanical efficiency of 91% and a static stress in the material, based on rated load, of ≤ 20% of assumed average ultimate strength of the material. These determinations are made from published data of cable breaking strengths.

Adjustment of cable lengths was made at installation.

To aid in understanding the rope reeving system, figure 10.20-4, 4-part reeving sketch, and figure 10.20-1, 16-part reeving system, are included.

D. Redundancy is provided in the main hook by incorporating a coaxial hook within-a-hook design. The shaft of the outer hook is bored out to accommodate the inner hook shaft. (See figure 10.20-5.) Each hook is independently supported by its respective crosshead and antifriction bearings that are supported by the bottom block. (See figures 10.20-1 and 10.20-2.) The sister hooks and bail holes are forged to ASTM specifications and tested to 200% design capacity. Each prong and cored bail hole have a design-rated capacity of 125 tons.

The conservative safety factor to ultimate is > 5. The load block, reeving cable, head block, drum, gear reducer, couplings, and motor shaft which make up the basic hoisting system all have a safety factor to ultimate in excess of 5.

E. The hoisting operation is protected by a regenerative braking system and two holding brakes and a redundant caliper brake. The regenerative brake system is a control type which prevents overspeed and is used to regulate load-lowering speed. Each holding brake and the caliper brake are safety, automatic actuation types, which have a sequential locking mechanism should the power fail or a cable break. These brakes are only released during operations when their system is energized. The caliper brake and provision for a second holding brake are located on the idler gear box. This unit is used for emergency load lowering should there be a malfunction in a drive gear component. The holding brake can stop and hold the rated load. These brakes are sized to 150% full-load motor torque as a minimum.

F. To prevent failures from occurring in the power train, gears are designed in accordance with the AGMA codes and bearing life is designed per CMAA Specification No. 70. A minimum gear safety factor of 5, developed from the calculated static stress in the material based on rated load, does not exceed 20% of assumed average ultimate strength of the material.

These components were magnetic particle inspected by properly qualified personnel in accordance with the American Society for Nondestructive Testing, Recommended Practice SNT-TC-IA, Supplement B, Magnetic Particle Inspection.

G. To prevent two-blocking (contact between the head and load blocks), redundant limit switches are provided. Overhoisting is sensed by a geared limit switch, driven by the drum shaft, counting revolutions. The geared limit switch also provides protection in the lowering motion by precluding the chance of the drum paying out fully and then reverse reeving.

H. The trolley and bridge travel have stepless control on travel speed from starting to full-design speed, which provide for the lowest impact due to acceleration. The trolley and bridge each have a regenerative and a holding brake system which lock should power fail and must be energized for operation. Brake systems are sized to 150% full-motor torque, except for the trolley motion brake which is sized for 50% motor torque.

I. Thermal overload protection is provided for all-electric power circuits which prevents continuation of motor stalling torque. An overload protection device is provided such that the rated capacity of the crane motor will not be exceeded. Table 10.20-3 gives data for the modified reactor building crane design. In addition to the thermal overload protection, both the main hoist and the 7 1/2-ton auxiliary hoist have Dillon overload protection switches installed and set to stop the hoisting motion in the event a lift $>$ 125% of rated capacity is attempted. The Dillon switch is a steel mechanical load deflection type of switch which is widely accepted in crane applications.

The maximum overspeed setpoint is established to prevent exceeding 5.5 ft/min when lowering full load. The response time to stop the hoisting motion, in the event of the activation of an overspeed or overload protection switch, is ~ 1 s.

Interlocks

Keyed electrical interlocks on the reactor building crane prevent the main hook from traveling over the spent-fuel pool. These interlocks are independent of the load being handled by the crane. The interlocks may be bypassed to permit handling of the spent-fuel racks, should this be required.

Loads

Specific loads which are routinely handled by the reactor building crane are given in table 10.20-4.

Handling

During normal plant operation, no objects are routinely handled over the reactor well, which is shielded by 6 ft of concrete. During a refueling operation, the following items are removed with the reactor pressure vessel (RPV) head in place:

- Reactor well shield plugs.
- Dryer-separator pool/reactor well shield plugs.
- Reactor well/spent-fuel pool shield plugs (but not the two gates).
- Drywell head.
- Drywell head insulation.

Following the removal of the RPV head, the steam dryers and the shroud head with moisture separators are removed. These latter items are the heaviest objects handled during refueling operations over an open reactor vessel. The handling of these items as well as the entire refueling operation is carefully controlled and governed by administrative procedures and controls.

The handling schemes used for the reactor head and the vessel internals are designed as manual operations, wherein a very minimum of auxiliary devices are used for positioning, but depend upon the operator using good judgment and having at least a minimum knowledge of rigging skills.

The reactor head is positioned using only two or three lead-in studs in place of the regular head studs. These lead-in studs are smooth above the flange surface and have a conical head for easy entry into the head stud holes.

The head is positioned using the main crane so that the lead-in studs are within 1 to 2 in. vertically above their appropriate holes. The head flange must be parallel to the vessel flange surface. The operator then lowers or jags the head to a position within 1/4 to 1/2 in. of the hole to stud alignment. He can then jag the head into place by observing where contact is made between the lead-in stud and the inner diameter of the hole.

Similar lead-in bolts are provided for vessel dryers and separator assemblies. The separator assembly has an alignment pin and hole to assure correct positioning. The dryer assembly utilizes the same lead-in bolt, but the positioning accuracy required is within tolerance of the lead-in clearance, and pins are not used. The same techniques of observation and trial and error positioning are used.

When handling new fuel between the shipping boxes, inspection stand, storage vault, and spent-fuel pool, similar care is required. The fuel can be positioned with 1/2- to 3/4-in. accuracy. The lead-in nose on the fuel engages the hole. The operator can then reposition the crane to permit easy entry into the rack. For minor misalignments the crane cable can be positioned by hand as the fuel is lowered. Table 10.20-3 provides a listing of the general data describing the present reactor building overhead crane. These parameters are accurate to the standard manufacturing tolerances of the crane industry.

Spent-Fuel Cask Handling and Spent-Fuel Cask Lift Yoke System

Refer to HNP-2-FSAR paragraph 9.1.5.2 for a description of the spent-fuel cask lift yoke system and paragraph 9.1.5.3 for a description of spent-fuel cask handling.

Safety is the prime concern during handling operations. Observance of the design limitations, procedures, and controls will prevent damage to spent fuel via objects dropped from hoisting devices. (Refer to drawing H-10167 for the refueling floor load paths.)

Equipment Failures

In the event that the hoist, trolley, or bridge become inoperable due to loss of power during a lift, the following procedure is followed to position and lower the load:

A. Four men are used - one handling a tachometer and each of the other men handling a special brake release wrench for each 150% torque motor brake.

B. Using the brake release wrench, two brakes are released completely to see if the other brake holds the full load. If not, the brake is adjusted per the maintenance instructions.

C. The test is repeated for the second and third brakes.

D. The load is lowered by having two men release two of the brakes completely. The third man holds the tachometer to the brake end of the motor. The fourth man releases the third brake. When the motor reaches one half the rated rpm of the motor, the second brake is reset.

E. In this manner the load is lowered in short increments with appropriate time intervals for excessive heat dissipation.

F. The bridge or trolley is moved by releasing the motor brake and turning the cross shaft with a wrench.

The NRC evaluated the structural fatigue for the reactor building crane and concluded that fatigue is not a significant concern.(1) Per TER-C5506-359/360 (an attachment to Reference 1), the fatigue requirements for the reactor building crane are not of consequence, since the crane is not used for frequent lifts at or near design conditions. This statement is still valid, even including the additional lifts associated with the independent spent fuel storage installation casks. The structural members are designed for a fatigue loading of 20,000 to 100,000 cycles with each completed lift representing one cycle. The rotating machinery is designed for a fatigue life expectancy of 2 million cycles with each rotating component cycle represented by 1 rpm. Any load below 50% of the crane-rated capacity has no effect on the life expectancy of the crane.

The crane design provides a safety factor of 5 for mechanical machinery. All lifting devices, slings, and load connections also have a minimum safety factor of 5. Slings for handling heavy loads (i.e., loads > 1250 lb) shall meet the requirements of ANSI B30.9-1971 with the exception that they are required to have an additional factor of safety of 2, beyond the factor of safety of 5 required by ANSI B30.9-1971 (i.e., for a resultant rigging factor of safety of 10), to account for dynamic loads.

The main hook is a two-pronged sister hook with a bail hole. It is designed with a safety factor of 5 when loaded equally on each prong with a maximum included sling angle of 60 degrees. The rated load may also be handled using the bail hole.

The reeving system consists of two separate ropes attached to an equalizing beam which provides for equal division of the load between the two ropes. With both ropes functioning and equalized, the safety factor of the ropes is 6.2 on a static basis. If one rope should fail, the remaining rope could support the load with a residual safety factor of 3.1 on a static basis.

Based on 125% load, the dynamic factor of safety for the main hoist is 4.72 and for the auxiliary hoist is 4.21.

Performance and Acceptance Testing

The performance and acceptance testing of the reactor building crane system included:

- *Detailed checking of the installed runway and assembled crane.*
- *Running-in test with 25 and 50% loads for live-load adjustments of all controls.*
- *Performance test with the 125-ton maximum rated load and the 125% test load.*

Instructions and procedures for operating, servicing, and maintaining the crane were prepared prior to and used during the performance and acceptance testing period. Records of the performance testing and adjustments made to system controls provide the basis for preparation of detailed operating procedures, instructions for handling specific loads, servicing requirements, and the maintenance program.

Following overhauls and major repairs to components of the crane, a complete performance and 125% proof test are conducted to verify and prove the integrity of the crane.

REFERENCES

1. Nuclear Regulatory Commission Safety Evaluation Report for the Edwin I. Hatch Nuclear Plant, dated April 19, 1984.

TABLE 10.20-1

REACTOR BUILDING CRANE SERVICE INFORMATION

Bridge		
Average lift		
Frequency (times/year)		48
Time duration (min)		7
Length of travel (ft)		36
Maximum lift		
Frequency (times/year)		5
Time duration (min)		7.8
Length of travel (ft)		40
Trolley		
Average lift		
Frequency (times/year)		46
Time duration (min at 5 ft/min)		5.4
Length of travel (ft)		27
Maximum lift		
Frequency (times/year)		5
Time duration (min)		8.2
Length of travel (ft)		8
Hoist	Main	Auxiliary
Average lift		
Time duration (min)		1.4
Travel distance (ft)	40	4
Weight (ton)	46	4
Frequency (times/year)	46	4
Maximum lift		
Time duration (min) (ascending)	35.3	1.4
Travel distance (ft)	126	4
Weight (ton)	125	7.5
Frequency (times/year/unit)	5	4
Cycle load range (ton)	9 to 125	1/4 to 4

TABLE 10.20-3 (SHEET 1 OF 2)

REACTOR BUILDING CRANE DATA

Bridge

Runway length (HNP-1) (ft-in.)	140 - 6
Bridge weight (lb)	261,200
Bridge span (ft-in.)	101 - 9
Bridge motor (hp)	2/10 hp at 1200 rpm
Type of wheels	Parallel tread
Number of wheels	8
Maximum speed (ft/min)	50 ft/min
Minimum speed (ft/min)	5.0
Minimum incremental distance (in.)	1/4
Type of controls	562N static stepless
Type of brake	2/8 in. CDH
Type of bumpers	Spring

Trolley

Length of trolley travel (ft-in.)	88 - 0
Trolley weight, net. (lb)	110,000
Trolley weight, with live load (lb)	360,000
Distance between running rails (ft-in.)	19 - 0
Trolley drive (hp)	2 1/2 hp at 720 rpm
Type of wheels	Parallel tread
Number of wheels	4
Maximum speed (ft/min)	10
Minimum speed (ft/min)	0.975
Minimum incremental travel (in.)	1/8
Type of controls	562N static stepless
Type of brakes	One disc brake on motor
Type of bumpers	Spring

TABLE 10.20-3 (SHEET 2 OF 2)

Hoists	Main	Auxiliary
Lifting capacity (ton)	125	7.5
Drum size, pitch circle diameter (in.)	72.75	15.125
Rope type	6/37 IWRC	6/37 IWRC
Rope size, diameter (in.)	1.25	0.5
Diameter top block sheaves, pitch circle diameter (in.)	30	None
Diameter hook block, pitch circle diameter (in.)	30	15
Type of equalizer	Bar	Bar
Type of hook	Forged	Forged
Type of hook material	AISI 1045	AISI 1045
Hook test load (ton)	250	15
Maximum travel of hook (ft/min)	126 - 0	126 - 0
Maximum hoist speed (ft/min) (descending)	4.95	28
Minimum hoist speed (ft/min)	0.42	2.8
Minimum incremental travel distance (in.)	1/32	1/8
No. of parts of rope	16	4
c/c sheaves in highest position	76-1/8	56-1/2
Type of control brakes	Eddy current	Eddy current
Type of holding brakes	2/13 in. CDR 1/Caliper Brake	2/8 in. CDR
Type of control	563N static stepless	563N static stepless

TABLE 10.20-4 (SHEET 1 OF 2)

SPECIFIC LOADS HANDLED BY REACTOR BUILDING CRANE[(a)]

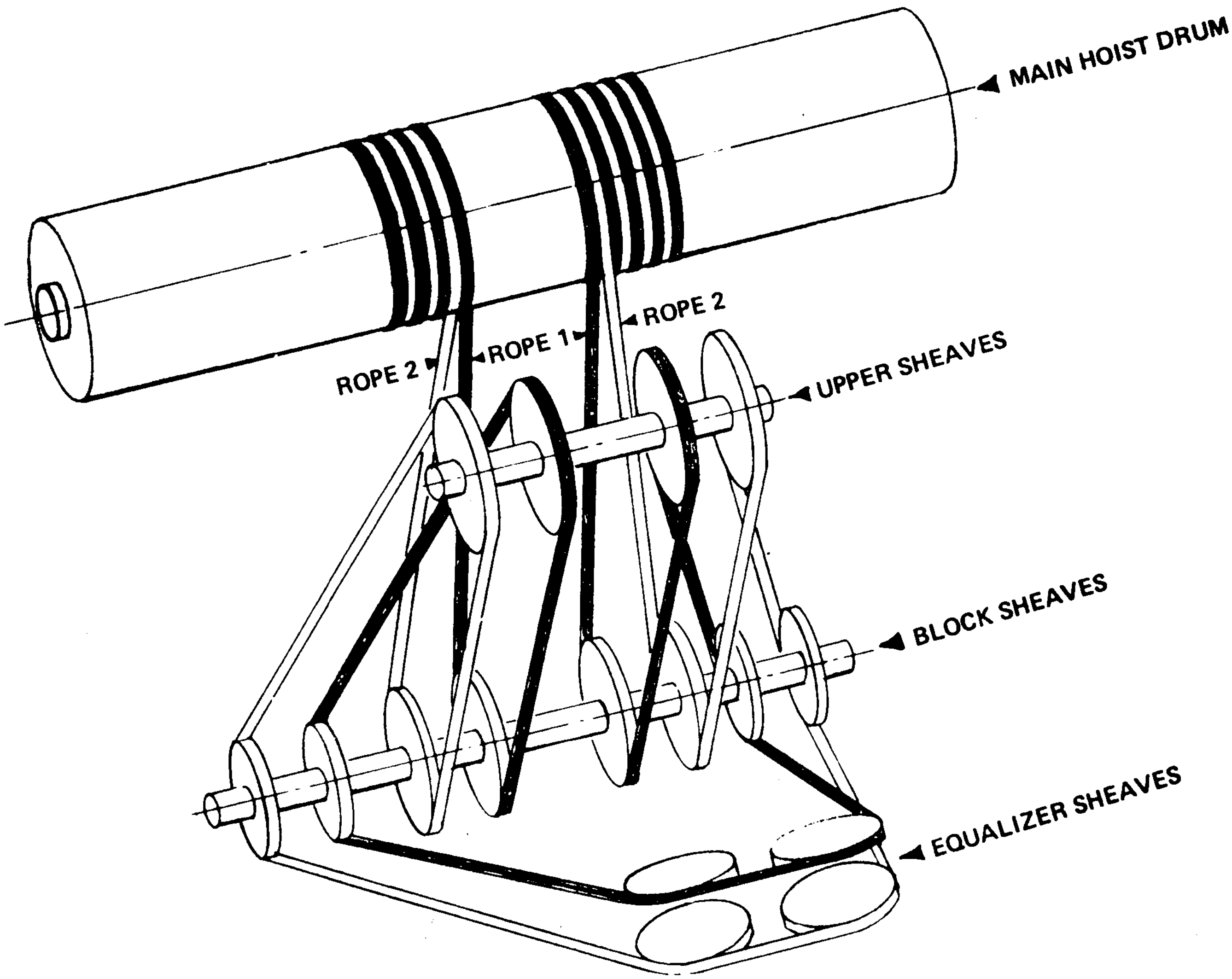
Reactor Equipment and Components Handled[(b)]	Load (tons)
Moisture separator	56
Steam dryer	29
Reactor pressure vessel head[(e)]	65
Reactor cavity shield plugs[(e)]	4 at 81 2 at 80
Spent-fuel pool plugs[(e)]	4 at 10
Reactor cavity/moisture separator pool plugs[(e)]	3 at 33 1 at 76
Drywell head[(e)]	45
Spent-fuel cask[(c, d)]	125
Reactor pressure vessel head insulation[(e)]	6
Reactor cavity/spent-fuel pool cattle chute[(c, e)]	16
360º auxiliary work platform[(c, d)]	70
Reactor pressure vessel head carousel / tensioner assembly including storage stands [(c, f)]	29
Head strongback[(c)]	8
Fuel pool gates [(e)]	6 at 3.75 (inner) 6 at 5.5 (outer)
Dryer separator pool gate[(e)]	20
Transfer canal seal assembly[(c, e)]	16

a. An identical set of these specific components is located in each unit.
b. See Drawing H-10167 for safe load path outline.
c. A common load for both units.
d. Spent fuel casks must be lifted by the HNP-1 reactor building crane.

TABLE 10.20-4 (SHEET 2 OF 2)

SPECIFIC LOADS HANDLED BY REACTOR BUILDING CRANE[(a)]

e. These items shall be lifted from their normal operating location by the HNP-1 reactor building crane main hook only.
f. Only the HNP-1 reactor building crane main hook shall be used to lift the reactor pressure vessel head carousel / tensioner assembly (with or without the reactor pressure vessel head attached.)



NOTE: RELATIVE POSITION OF SHEAVES IS EXTENDED AND ANGLE OF VIEW IS DISTORTED TO CLARIFY REEVING PATHS.

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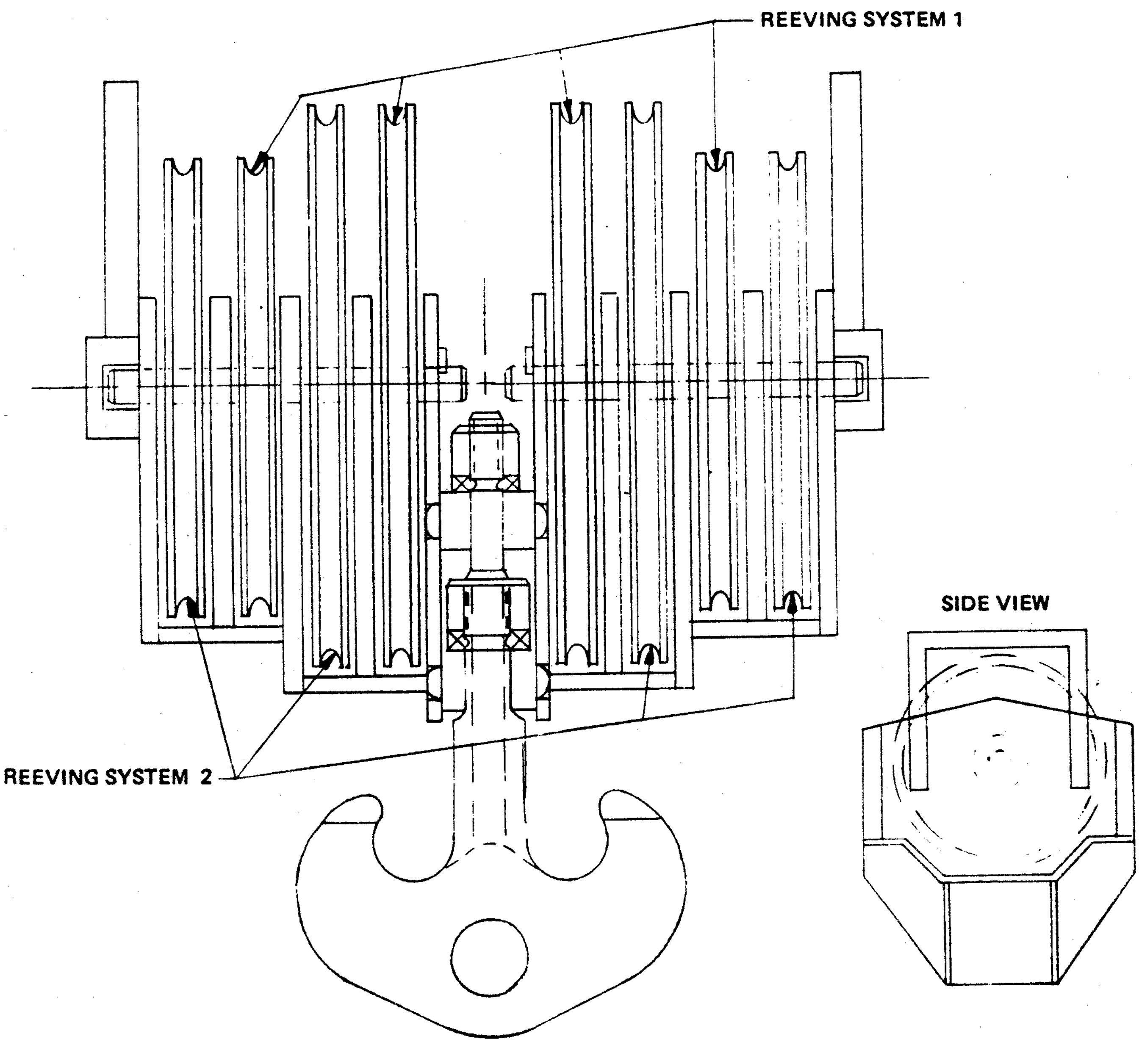
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

REACTOR BUILDING OVERHEAD CRANE
MAIN HOIST
16-PART REEVING SYSTEM

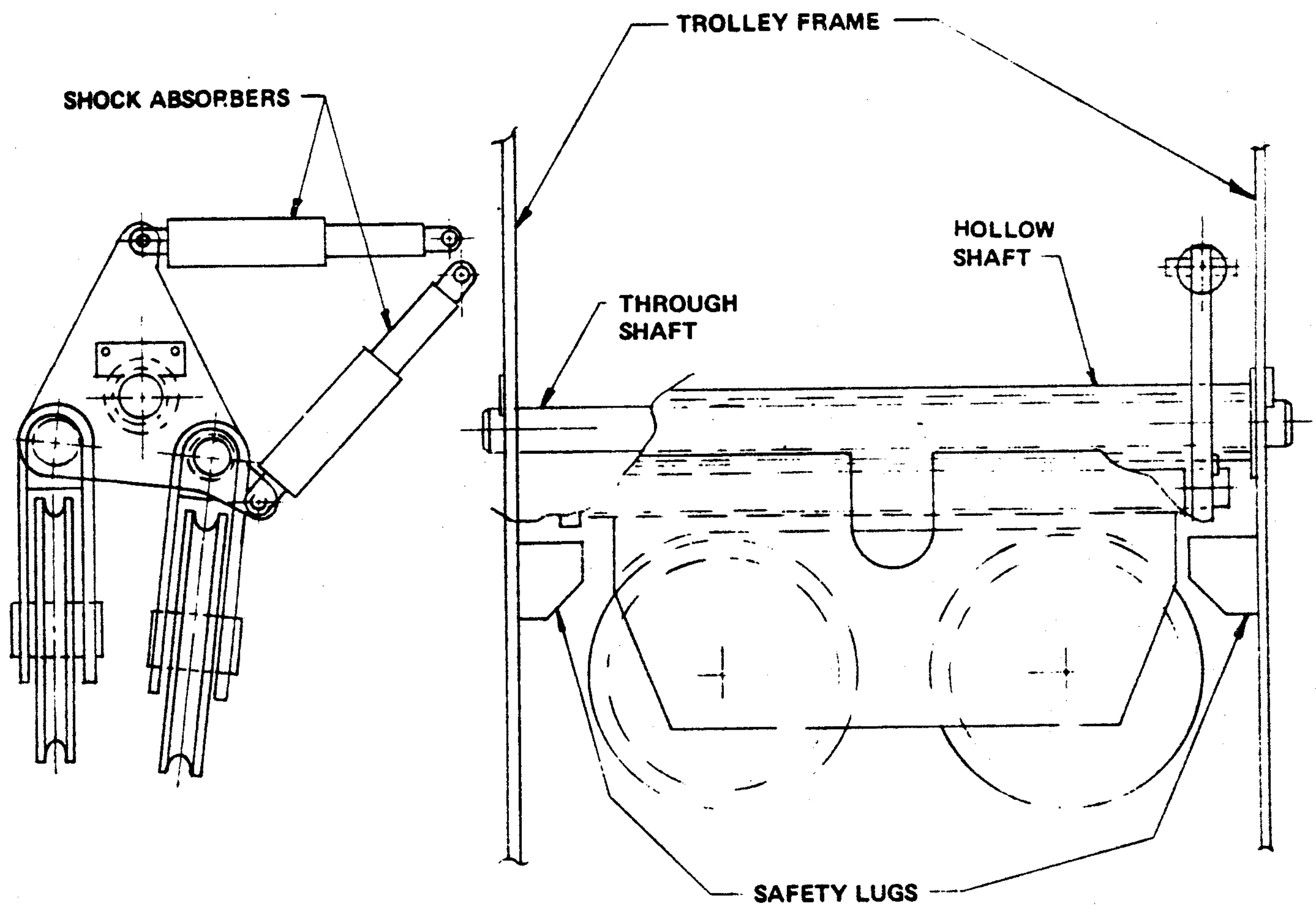
FIGURE 10.20-1



REV 19 7/01

REACTOR BUILDING OVERHEAD CRANE
MAIN HOIST
LOAD BLOCK ASSEMBLY

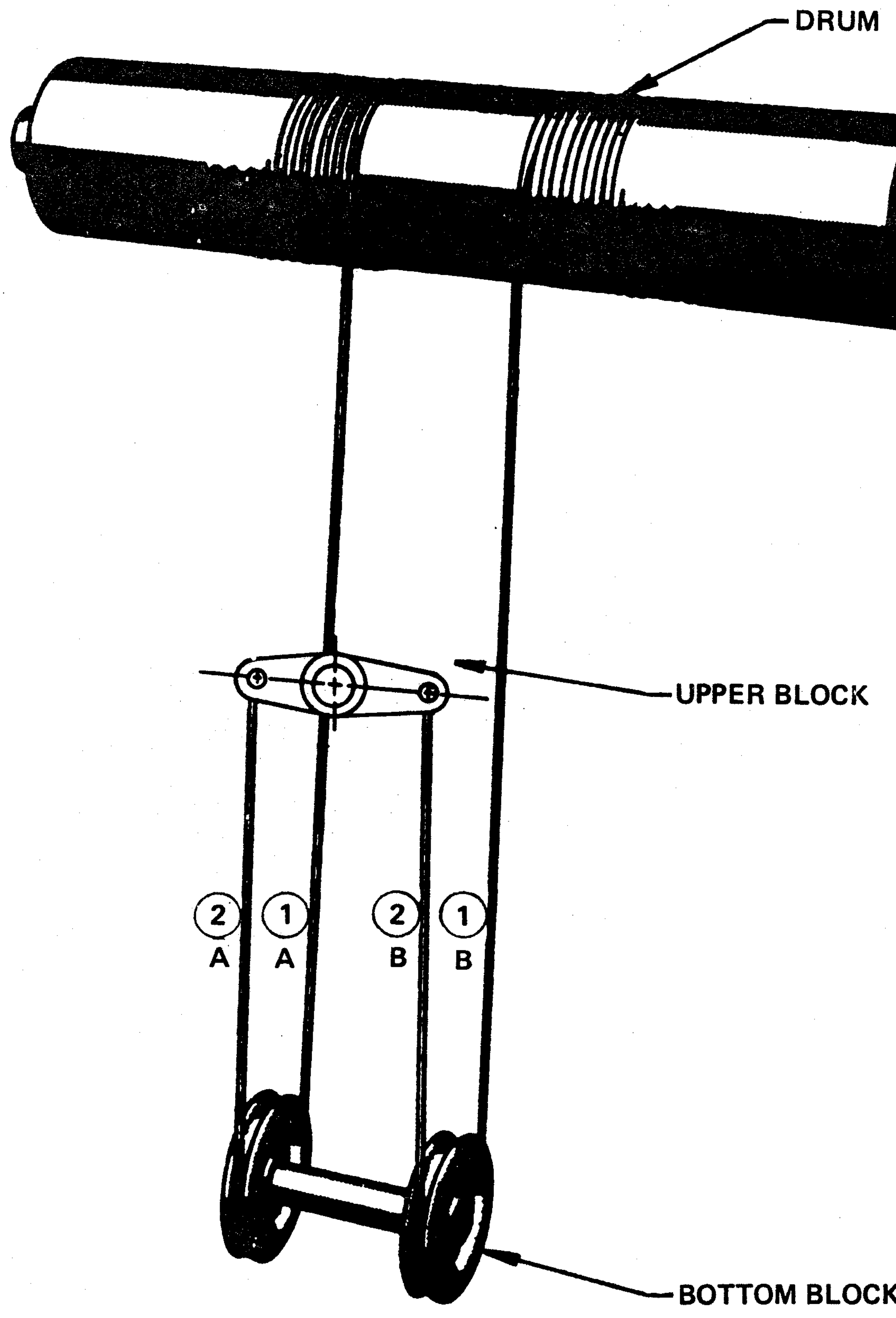
FIGURE 10.20-2



REV 19 7/01

REACTOR BUILDING OVERHEAD CRANE
EQUALIZER ASSEMBLY

FIGURE 10.20-3



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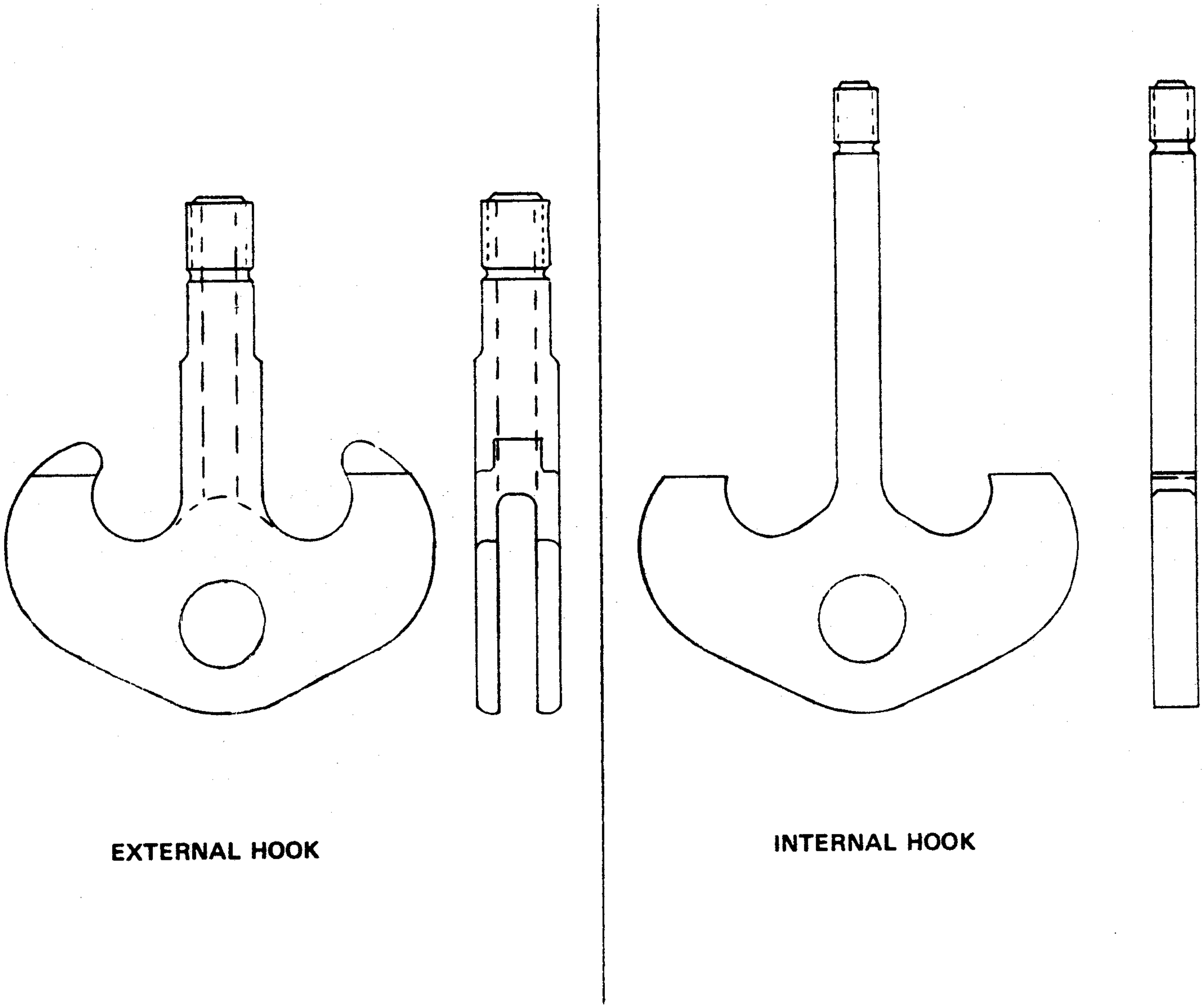
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

REACTOR BUILDING OVERHEAD CRANE
AUXILIARY HOIST
4-PART REEVING SKETCH

FIGURE 10.20-4



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

REACTOR BUILDING OVERHEAD CRANE
MAIN HOIST (HOOK WITHIN A HOOK)
HOOK ARRANGEMENT

FIGURE 10.20-5

10.21 OXYGEN STORAGE

There is provision for standard oxygen bottles used for welding. These standard bottles are stored away from the main plant.

Also, there is a hydrogen water chemistry cryogenic storage facility which contains a liquid oxygen storage tank. This facility is described in subsection 11.10.3.

10.22 GEZIP PASSIVE ZINC INJECTION SYSTEM

General Electric developed the General Electric Zinc Injection Passivation (GEZIP) process to control radiation buildup in boiling water reactors. Soluble zinc in the reactor feedwater inhibits the corrosion of stainless steel. Soluble zinc in the reactor water also inhibits the transport and the deposition of Cobalt-60 from the fuel to the reactor coolant pressure boundary surfaces, thereby reducing radiation buildup on these surfaces.

The passive zinc injection system is designed to continuously inject a dilute solution of ionic zinc in water into the reactor feedwater. A stream of water taken from the common reactor feedwater pump discharge is routed through a column containing zinc oxide pellets. The dissolution of sintered zinc oxide pellets into the diverted feedwater stream provides the ionic zinc. The dissolved zinc oxide in the stream leaving the dissolution column is returned to the common reactor feedwater pump suction and is blended with the main feedwater flow.

Reactor water zinc levels are measured periodically. Based upon the results of these measurements, the flow through the passive zinc injection system can be adjusted to maintain the reactor water zinc concentration at the desired level.

The injection rate of the zinc into the feedwater is adjusted by controlling the rate of water flow through the dissolution column and varying by the amount of zinc oxide pellets in the column, with the primary means of control being water flowrate through the column. The water flowrate through the dissolution column is controlled by the manual positioning of the opening of a flow control valve. The dissolution column is filled with sufficient zinc oxide to last through one complete fuel cycle.

The zinc dissolution rate is naturally reduced during reactor power reduction since the rate is a function of temperature. As reactor power is reduced, feedwater temperature decreases, reducing the rate of zinc dissolution into the diverted feedwater stream passing through the dissolution column.

The GEZIP passive zinc injection system is not safety related because it is not required for safe operation or shutdown of the plant, and it does not impact the operation, function, or integrity of any safety-related equipment or systems.

10.23 DRY SPENT-FUEL STORAGE

See HNP-2-FSAR subsection 9.1.5 for a description of dry spent-fuel storage.

10.24 MAIN STEAM ISOLATION VALVE LEAKAGE TREATMENT SYSTEM

See HNP-2-FSAR subsection 9.5.10 for a description of this system.

11.0 POWER CONVERSION SYSTEMS

11.1 SUMMARY DESCRIPTION

The power conversion systems are designed to produce electrical energy through conversion of a portion of thermal energy contained in the steam supplied from the reactor, to condense the turbine exhaust steam into water, and to return the water to the reactor as heated feedwater with a major portion of its gaseous, dissolved, and particulate impurities removed. The heat rejected to the main condenser is removed by the circulating water system utilizing cooling towers.

In special cases, the HNP Operations Department can be requested by the Southern electric system Control Center to vary the output of HNP-1, as required, to support system needs. Normally, the unit is operated at base load, but is designed to take its operational share of system control and regulation.

The major components of the power conversion systems are shown on drawing nos. H-11018 through H-11020, H-11601 through H-11608, and H-11646.

The saturated steam produced by the boiling water reactor is passed through the high-pressure turbine where the steam is expanded. The steam is then exhausted to the moisture separator reheaters (MSRs) where moisture is removed, and the steam is reheated. The steam is next passed through the low-pressure turbines where the steam is again expanded. From the low-pressure turbines, the steam is exhausted into the condenser where the steam is condensed, deaerated, and returned to the cycle as condensate. A small part of the main steam supply is continuously used by the steam jet air ejectors (SJAEs). The condensate pumps, taking suction from the condenser hotwell, deliver the condensate through the air ejector condensers, turbine gland-seal condenser, and condensate demineralizer to the suction of the condensate booster pumps. The booster pumps deliver the condensate through four stages of low-pressure feedwater heaters to the reactor feed pumps. The reactor feed pumps supply feedwater through one stage of high-pressure feedwater heaters to the reactor. Steam for heating the feedwater in the heating cycle is supplied from turbine extractions. The feedwater heaters also provide the means of handling the moisture separated from the steam in the turbine and in the MSRs.

Normally, the turbine utilizes all the steam being generated by the reactor; however, an automatic pressure controlled steam bypass system is provided to discharge excess steam up to ~ 21% of rated steam flow directly to the condenser.

One of the design bases of the pressure regulator and turbine-generator control system is to match nuclear steam supply to turbine steam requirements by adjustment of recirculation system flow to satisfy load demand. Reactor pressure regulation, turbine-generator controls, and turbine-generator protection are performed by the GE Speedtronic Mark VI electrohydraulic control (EHC) system. Plant Hatch does not utilize the automatic load-following capabilities of the recirculation flow control system. Refer to section 7.11 for a discussion of the pressure regulator and turbine-generator control system.

The power conversion systems are suitable for operation at current 100% rated conditions at 2804 MWt and 1060 psia reactor pressure as demonstrated in the safety analysis report for thermal power optimization[(1)] and the reactor operating pressure increase reviews.[(2)]

REFERENCES

1. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

2. RER 03-254, Reactor Operating Pressure Increase from 1050 psia to 1060 psia, Engineering Evaluations.

11.2 TURBINE GENERATOR

11.2.1 POWER GENERATION OBJECTIVE

The objective of the turbine-generator is to receive steam from the boiling water reactor, to economically convert a portion of the thermal energy contained in the steam to electric energy, to provide extraction steam and moisture for feedwater heating, and to provide extraction steam for driving the reactor feed pump turbines.

11.2.2 POWER GENERATION DESIGN BASIS

The turbine-generator and the associated systems, and their control characteristics, are integrated with the features of the reactor and associated nuclear systems to obtain an efficient and safe power generating unit.

11.2.3 DESCRIPTION

The turbine-generator consists of the following components:

- Turbine.
- Generator.
- Exciter.
- Controls and required subsystems.

The turbine is a tandem compound, reheat unit with 43-in. last-stage buckets. It consists of a double-flow high-pressure turbine and two double-flow low-pressure turbines. Exhaust steam from the high-pressure turbine passes through moisture separator reheaters before entering the two low-pressure turbines.

The generator is a direct coupled, three-phase, 60 Hz, 24,000-V, conductor cooled, synchronous generator rated 1,050,000 kVa, with a short circuit ratio of 0.58 and a maximum hydrogen pressure of 60 psig.

The exciter system is EX2100 multibridge static excitation system. The power for the generator field is drawn for 24 – 0.8-kV, 5600-kVA power potential transformer (PPT) at the generator terminals. The primary side of the PPT is connected by a tap off of the existing generator isophase bus. The secondary side of the PPT is connected through isophase bus to the EX2100 AC termination, which supplies power to the exciter bridge input. The AC power from PPT secondary side is converted to DC by a three-phase, full wave, inverting thyristor bridge (SCR) to provide rated field current to the generator field.

The trip logic on the exciter field breaker trips the breaker automatically when a turbine trip occurs. This prevents over excitation of the generator and, therefore, precludes damage to the generator insulation.

The turbine utilizes an electrohydraulic control (EHC) system consisting of normal governing devices, emergency devices for turbine and plant protection, and special control and test devices. The EHC system operates the main stop valves, control valves, bypass valves, crossover combination stop-intercept valves, and other protective devices. Turbine governor functions and turbine control are covered more fully in chapter 7, Control and Instrumentation.

For overpressure protection of the turbine exhaust hoods and the condenser shells, two rupture diaphragms are provided on each turbine exhaust hood.

The turbine-generator is provided with supervisory instrumentation and controls in the main control room.

Fifteen hydrogen storage cylinders containing hydrogen for generator cooling for both HNP-1 and HNP-2 are described in HNP-2-FSAR subsection 10.2.2.

11.2.4 POWER GENERATION EVALUATION

Anticipated operational occurrence analyses were performed for the turbine generator system are included in HNP-2-FSAR chapter 15, section 15.2.

Thorough examinations are made of each turbine wheel at the time of manufacture. Most wheels used have no crack indications. If crack indications are detected, these indications are assumed to be "cracks." Conservative assumptions are applied to the indications such as maximum size and most critical orientation for its location. The growth of these assumed cracks is calculated for the maximum number of cycles. If these calculations show that any assumed cracks might grow to critical size during the lifetime of the unit, the wheel is rejected.

Every 8- or 10-year period the turbine will be disassembled for a major inspection during which time the turbine rotor is removed from the unit, thoroughly cleaned, and given a nondestructive examination, in accordance with the turbine manufacturer's recommendation, to determine its integrity. Based on the issuance of GE's Technical Information Letter 1008-3R1, an inspection period of every 8 to 10 years is sufficient for detecting conditions that would promote failures of the last-stage wheels in the low-pressure turbines whose rpm rating is 1800. As to whether an 8-year interval compared to a 10-year interval is chosen depends on which turbine is being inspected: the high-pressure turbine or the low-pressure turbine. If no crack propagation evaluation is done, an 8-year interval will be applied for integrity evaluation of the low-pressure turbine and a 10-year interval for the high-pressure turbine. Otherwise, a 10-year evaluation interval for the high-pressure and low-pressure turbines will be adhered to.

11.2.5 TURBINE-MISSILE ANALYSIS

In 1986, the NRC approved the GE methodology for evaluating the probability of wheel missile generation for nuclear turbines manufactured by GE (reference NUREG-1048, Appendix U). The GE "Turbine Missile Analysis Statement," dated June 18, 2010, defines the annual probability for turbine missile generation for Hatch Unit 1 as 1.71 x 10^{-6}, which is below the NRC-defined limit of 1 x 10^{-5}. The assessed turbine configuration includes GE supplied monoblock low pressure (LP) rotors with the GE Mark VI control system. Refer to HNP-2-FSAR paragraph 10.2.3.1 for more information.

11.3 MAIN CONDENSER

11.3.1 POWER GENERATION OBJECTIVE

The objective of the main condenser is to provide a heat sink for the turbine exhaust steam, turbine bypass steam, and other flows. It also deaerates and provides storage capacity for the condensate, which will be reused after a period of radioactive decay.

11.3.2 POWER GENERATION DESIGN BASES

A. The main condenser is a two-shell, single-pass, divided water box, deaerating type, with a condenser duty of 6.615×10^9 Btu/h; an inlet water temperature of 90°F; and an average back pressure of 4.12-in. Hg absolute.

B. The condenser accepts up to ~ 21% of rated main steam flow through the turbine bypass without increasing back pressure beyond turbine trip setpoint or exceeding turbine exhaust temperature.

C. The condenser deaerates the condensate and removes noncondensible gases from the condensing steam and air in leakage. Specified oxygen content of condensate is limited to 0.005 cc/l (7.0 ppb) over a load range of 25% to 100%.

11.3.3 DESCRIPTION

During planned operation, steam from the low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows, such as exhaust steam from feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents.

Other flows occur periodically; they originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, makeup and condensate, etc.

The condenser is designed to receive turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge (from feedwater heater shells, steam-seal regulator, and various steam supply lines) during abnormal conditions.

The main condenser is a two-shell, single-pass, single-pressure deaerating type with a reheating-deaerating hotwell and divided waterboxes. The condenser consists of two sections, and each section is located below one of two low-pressure elements of the turbine. The condensers are supported on the turbine room foundation mat, with stainless-steel expansion joints provided between each turbine exhaust opening and the steam inlet connections in the condenser shells.

The inlet and outlet waterboxes of the condenser shells are each provided with circulating water valves, permitting either half of either condenser shell to be removed from service.

Conductivity elements detect tube sheet inleakage of circulating water into the condenser steam space.

Should the bypass, control, or turbine stop valves fail to close on loss of condenser vacuum, two rupture diaphragms on each turbine exhaust to the condenser protect the condenser and turbine exhaust hoods against overpressure.

Deaeration in the condenser removes air inleakage and radiolytic hydrogen and oxygen.

The noncondensible gases are concentrated in the air-cooling section of the condenser, from which they are removed by the mechanical vacuum pump at startup and by the steam jet air ejectors during normal operation.

11.4 MAIN CONDENSER GAS REMOVAL AND TURBINE SEALING SYSTEMS

11.4.1 POWER GENERATION OBJECTIVE

The objective of the main condenser gas removal system is to remove all noncondensible gases from the condenser.

The objective of the turbine sealing system is to prevent air leakage into or steam leakage out of the turbine.

11.4.2 POWER GENERATION DESIGN BASES

A. The main condenser gas removal system is designed to remove all noncondensible gases from the condenser, including air inleakage and dissociation products originating in the reactor, and exhaust them to the off-gas holdup system.

B. The turbine sealing system is designed to provide the means of sealing with steam the turbine shaft glands and the valve stems (the main stop, control, combined intercept, and bypass valves). The condensed steam from the sealing system is returned to the main condenser, and the noncondensible gases are exhausted to the off-gas holdup system.

11.4.3 DESCRIPTION

11.4.3.1 Main Condenser Gas Removal System

For planned operation, the main condenser gas removal system includes two 100% capacity, three-stage steam jet air ejector (SJAE) units, complete with inter- and after-condensers. These units remove air and noncondensible gases from the main condenser. (See drawing nos. H-11025, H-11612, and H-11613.) A mechanical vacuum pump is provided for startup and shutdown.

11.4.3.1.1 Steam Jet Air Ejectors

Main steam, reduced in pressure by its associated automatic steam pressure reducing station, is the motive flow for the SJAEs. The first-stage air ejector takes suction directly on the condenser air-cooling section and discharges to the first inter-condenser. The second-stage air ejector takes suction on the first inter-condenser and discharges to the second inter-condenser. The third-stage SJAE takes suction on the second inter-condenser and exhausts/discharges the gas vapor mixture to the off-gas system. (See section 9.4.) The inter-condensers are cooled by condensate, and condensation occurring in the inter-condensers is returned to the condenser hotwell for reuse.

Improper operation of the air ejectors would result in a loss of condenser vacuum which would initiate main steam line isolation.

11.4.3.1.2 Mechanical Vacuum Pump

When the desired rate of air and gas removal exceeds the capacity of the SJAEs (when reactor power is ≤ 5%), or when the steam supply to the SJAEs is not adequate to provide for their operation, the mechanical vacuum pump is used to evacuate the condenser.

11.4.3.2 Turbine Sealing System

The turbine sealing system consists of the seal steam pressure regulator, the steam seal header, one gland-seal condenser with two exhaust blowers, and associated piping and valves. The pressure regulator maintains the steam seal header at constant pressure.

On pressure packings (the high-pressure turbine shaft and stop, control and bypass valve stems), sealing steam is extracted. On subatmospheric packings (low-pressure turbine shafts), steam is supplied from the steam seal header. The outer ends of all glands are routed to the gland-seal condenser, which is maintained at a slight vacuum by the exhaust blower. The exhaust blower delivers air and non-condensible gases to the gland-seal off-gas holdup system. The gland-seal condenser is cooled by main condensate. During periods when the gland condenser or blower is out of service, the glands exhaust to the main condenser.

11.5 TURBINE BYPASS SYSTEM

11.5.1 POWER GENERATION OBJECTIVE

The objective of the turbine bypass system is to dissipate the energy of main steam generated by the reactor which cannot be utilized by the turbine.

11.5.2 POWER GENERATION DESIGN BASES

A. The turbine bypass system is designed to control reactor pressure:

- During reactor heatup to rated pressure.
- While the turbine is brought up to speed and synchronized.
- During power operation when the reactor system generation exceeds the transient turbine steam requirements and limitations.
- During cooldown of the reactor.

B. The turbine bypass system capacity was originally based on 25% of the turbine design flow. At current 100% power conditions (2804 MWt), the bypass valve capacity is conservatively calculated to be ~ 21% of rated steam flow.

11.5.3 DESCRIPTION

The turbine bypass system consists of automatically and sequentially operated regulating valves mounted on a valve manifold. The manifold is connected to the main steam lines upstream of the turbine main stop valves. The bypass valve outlets are piped to the main condenser and pressure reducing orifices are located at the condenser connection.

The basic operation of the turbine bypass system is that it receives from the turbine control system (initial pressure regulator) a signal to open the bypass valves whenever the actual steam pressure exceeds the preset steam pressure. This occurs whenever the amount of steam generated by the reactor cannot be entirely absorbed by the turbine.

The bypass valves are tripped closed whenever the vacuum in the main condenser falls below a preset value.

11.5.4 POWER GENERATION EVALUATION

The effects of turbine bypass system malfunctions and the effect of such failures on other components are evaluated in HNP-2-FSAR chapter 15, Safety Analysis, sections 15.2 and 15.4.

11.5.5 INSTRUMENTATION APPLICATION

Instrumentation applicable to the control of the turbine bypass system is discussed in section 7.9, Recirculation Flow Control System, and section 7.11, Pressure Regulator and Turbine Generator Control System.

11.6 CIRCULATING WATER SYSTEM

See HNP-2-FSAR subsection 10.4.5.

11.7 CONDENSATE DEMINERALIZER SYSTEM

11.7.1 POWER GENERATION OBJECTIVE

The objective of the condensate demineralizer system is to maintain the required purity of feedwater flowing to the reactor.

11.7.2 POWER GENERATION DESIGN BASES

A. The system removes dissolved and suspended solids from the feedwater to maintain a high reactor feedwater quality.

B. The system provides final polishing of makeup water entering the feedwater loop.

C. The system maintains high-purity water rejected to the condensate storage and transfer system.

11.7.3 DESCRIPTION

The condensate demineralizer system consists of seven filter-demineralizers which operate in parallel. The filter-demineralizers are of the precoatable, backwashable type, using powdered cation/anion resins as the coating medium. In addition to the filter-demineralizers, the condensate demineralizer system includes the associated piping, valves, instrumentation, controls, and a body feed system. With the filter-demineralizer operating, the body feed system adds resin to the filter demineralizer vessels. The purpose of the resin addition is to increase the operation time of the filter-demineralizer before backwash and precoating maintenance is required. This system is skid mounted and includes an enclosed mixing tank with nitrogen inerting, a recirculation pump, two feed pumps (one spare), the required valves and piping, and a control panel. Instrumentation includes an automatic flow-balancing control which maintains equal flow through each onstream unit.

The condensate demineralizer system is controlled from local panels. Valves and pumps are remotely operated. Pressure differential and conductivity monitors are provided for each demineralizer to indicate when it is exhausted. Pressure drop and system influent and effluent conductivities are monitored and suitably alarmed. An automatic bypass maintains condensate system flow in the event the number of demineralizers in service is insufficient to maintain the required flow. The bypass opens when high-pressure differential occurs across the condensate demineralizer system. High-pressure differential and the opening of the bypass valve are annunciated.

The condensate demineralizer system is sized to limit the condensate impurity concentration during planned operations and in periods of peak contamination.

The filter-demineralizers remove some radioactive material created by corrosion product and fission product carryover from the reactor. While radioactivity effects from these sources do not affect the capacity of the resins, the concentration of such radioactive material requires shielding, which is provided for the condensate demineralizer equipment (chapter 12, Structures and Shielding). Waste sludge from the filter-demineralizers is sent to the radwaste system for disposal (chapter 9, Radioactive Waste Systems).

11.8 CONDENSATE AND FEEDWATER SYSTEM

11.8.1 POWER GENERATION OBJECTIVE

The power generation objective of the condensate and feedwater system is to provide a dependable supply of feedwater to the reactor, to provide feedwater heating, and to maintain high quality feedwater.

11.8.2 POWER GENERATION DESIGN BASES

A. The feedwater equipment provides the required flow at required pressure to the reactor, allowing sufficient margin to provide continued flow under anticipated operational occurrence conditions.

B. The feedwater heaters are designed to provide the required feedwater temperature to the reactor with five stages of closed feedwater heating.

C. A startup recirculation line from the reactor feedwater supply lines to the condenser hotwell is provided to minimize corrosion product input to the reactor.

11.8.3 DESCRIPTION

The vertical condensate pumps take the condensate from the condenser hotwells and pump it through the air ejector condensers, the gland-seal condenser, and the condensate demineralizers. The horizontal condensate booster pumps take the demineralizer effluent and pump it through two parallel streams of four low-pressure heaters to the suction of the reactor feed pumps. The reactor feed pumps then pump the feedwater through two parallel streams of one high-pressure heater to the reactor (drawing nos. H-11019, and H-11603 through H-11605).

11.8.3.1 Vertical Condensate Pumps

Each condensate pump is a multistage vertical, canned suction-type, motor-driven, centrifugal unit. The pumps are installed at an elevation that permits full-capacity operation down to extreme low level in the condenser hotwell. The pumps provide maximum design flow plus design margins at the required pressure to overcome system resistance and provide the required suction pressure at the horizontal condensate booster pumps. Logic is provided to autostart the standby condensate pump on condensate booster pump low-suction pressure.

11.8.3.2 Horizontal Condensate Booster Pumps

Each horizontal condensate booster pump is a single-stage, double-suction, motor-driven centrifugal unit. The pumps provide maximum design flow, plus design margins, at the required pressure to overcome system resistance and provide the required suction pressure at the reactor feed pumps. Logic is provided to autostart the standby condensate booster pump on reactor feed pump low-suction pressure. Also, time delay logic staggers the condensate booster pumps' low-suction pressure trips to prevent total reactor feed pump suction loss and subsequent trip of both reactor feed pumps during a plant transient.

11.8.3.3 Feedwater Heaters

Two parallel strings of heaters, each consisting of five reactor feedwater heaters, are provided. Heaters 1, 2, 3, and 4 are located before the reactor feed pumps, and heater 5 is located after the reactor feed pump. All feedwater heaters have stainless steel tubes and welded tubes to tube sheet joints.

11.8.3.4 Reactor Feed Pumps

Two turbine-driven reactor feed pumps are provided. Each reactor feed pump is a horizontal, centrifugal unit. The feed pumps operate in series with the condensate pumps and condensate booster pumps to provide maximum design flow, plus design margins, at the required pressure at the reactor inlet nozzles. Time delay logic staggers the reactor feed pumps' low-suction pressure trips to prevent the total loss of feedwater flow and subsequent unit trip.

Recirculation control valves are provided in the feed pump discharge lines to permit direct recirculation of feedwater to the main condenser. This assures minimum flow through the feedwater pumps.

11.8.3.5 Reactor Feed Pump Turbine Drives

Individual steam turbines drive the feedwater pumps. The turbine drives are the dual admission-type, and each is equipped with two sets of main stop and control valves. One set admits high-pressure steam from the reactor, and the other set admits low-pressure steam extracted from the main turbine crossover piping. Under normal operating conditions, the turbine drives run on low-pressure crossover steam. Reactor steam is used during plant startup, low-load, or transient conditions when low-pressure crossover extraction steam is either not available or is insufficient.

11.8.3.6 Feedwater Controls

The feedwater control system is described in chapter 7, Control and Instrumentation.

11.8.4 POWER GENERATION EVALUATION

The analysis for the loss of feedwater flow (LOFW) event is provided in HNP-2-FSAR chapter 15, Safety Analysis, section 15.2.

One vertical condensate pump, one horizontal condensate pump, and one reactor feedwater pump, operating in series, are capable of maintaining sufficient flow to the reactor to prevent a scram upon loss of any one pump in the stream while operating with two streams.

A bypass is provided around the reactor feed pumps for startup and shutdown operations, using the motor-driven condensate booster pumps for feeding the reactor.

11.9 CONDENSATE STORAGE SYSTEM

11.9.1 POWER GENERATION OBJECTIVE

The power generation objective of the condensate storage system is to provide condensate for system makeup needs and to take system "reject" surges.

11.9.2 POWER GENERATION DESIGN BASIS

The condensate storage system provides plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type services. The total stored design quantity is based on the demand requirements during refueling for filling the dryer separator pool and the reactor well.

11.9.3 DESCRIPTION

A 500,000-gal condensate storage tank (CST) supplies the various unit requirements. The condensate storage system also consists of two condensate transfer pumps and associated piping and valves.

The condensate tank provides the preferred supply to the high-pressure coolant injection and reactor core isolation cooling system. All other suctions are located above suction lines for these systems to provide an approximately 100,000-gal reserve.

A cross-connect line between HNP-1 and HNP-2 CSTs provides the capability to transfer water between the two tanks. This connection increases condensate storage capacity to either unit.

A Seismic Class 1 concrete structure is provided around the CST and the transfer pumps. This structure is of sufficient size to retain the contents of the tank in the unlikely event of damage to the tank or pumps.

11.10 HYDROGEN WATER CHEMISTRY SYSTEM

See HNP-2-FSAR subsection 10.4.8.

12.0 STRUCTURES AND SHIELDING

12.1 SUMMARY DESCRIPTION

The principal buildings and structures are the reactor building, control building, turbine building, diesel generator building, radwaste building, radwaste building addition, off-gas recombiner building, waste gas treatment building, service building, intake structure, cooling towers, and main stack.

Drawing nos. H-12626, H-12628, H-12632, H-15851, H-15852, H-15854, H-16027, H-16029, and H-16030 through H-16033 show the general arrangement of the reactor building, turbine building, service building, control building, and radwaste building. Drawing nos. H-12192, H-12320, H-16036, H-16519, and H-16536 show the general arrangements of the intake structure, diesel generator building, radwaste building addition, off-gas recombiner building, and waste gas treatment building. The service building, control building, waste gas treatment building, main stack, intake structure, and other auxiliary structures built for HNP-1 are also utilized for HNP-2. The relative locations of the intake structure, diesel generator building, radwaste building addition, off-gas recombiner building, waste gas treatment building, main stack, cooling towers, and other buildings are as shown on drawing no. E-10173.

Shielding and access control are provided for the radiation protection of individuals. Radiation protection is provided in accordance with the limits and guidelines of appropriate regulations.

12.2 DESCRIPTION OF PRINCIPAL STRUCTURES

12.2.1 REACTOR BUILDING

The reactor building encloses the reactor, reactor primary containment, auxiliary cooling systems, new-fuel storage vault, and spent-fuel storage pool. The reactor building provides secondary containment for the reactor and primary containment for auxiliary systems. Primary containment for the reactor consists of the drywell and the pressure suppression chamber discussed in chapter 5. The reactor building is basically a reinforced concrete structure, with structural steel framing, consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete floors supported by structural steel framing.
- Reinforced concrete or concrete block interior walls.
- Stainless-steel-lined reinforced concrete spent-fuel pool, reactor well, steam dryer-separator storage pool, and fuel transfer canal.
- High-pressure coolant injection room integral with reactor building.
- Reinforced concrete exterior walls up to refueling floor level.
- Exterior walls above the refueling floor consist of structural steel columns and prefabricated concrete panels.
- Reinforced concrete slab on metal roof deck system supported by steel framing.
- Steel primary containment.

All exterior doorways in the reactor building are designed to resist the full effects of tornado winds, depressurization, and horizontal missiles specified in paragraph 12.3.4.1 without exceeding the minimum yield strength of the doors, except plastic deformation up to a ductility ratio of 5 is permitted to resist the portion of the loading due to the missile.

There are no structural elements connecting the reactor building to any of the adjacent buildings. Adjacent buildings are separated by 3 in., above the grade level, and the maximum design basis earthquake (DBE) relative deflection is on the order of 0.3 in.

From table 4-7.1 of Engineering Mechanics - Pletta, Ronald Press Company, 1964, the coefficient of friction between rubber and concrete was adopted for the coefficient of friction between waterproof membrane and concrete for reactor building base slab.

The safety factor against sliding varies with the lateral soil pressure, the roughness of the concrete surface, and the frictional resistance along the concrete walls and the building base.

For obtaining a conservative safety factor against sliding without interpolating all the uncertainties, only the frictional resistance between the membrane and the building slab was considered. The total weight of the building multiplied by a friction factor of 0.8 provides 132,000 kips of sliding resistance which, when divided by the DBE shear of 25,870 kips, results in a safety factor of about 5 against sliding.

The reactor building railroad airlock construction details are shown in figure 12.2-2. The structure consists of reinforced concrete designed to the same seismic and tornado criteria as the reactor building. Due to dissimilarity in the seismic and normal settlement response of the reactor building and the projecting railroad airlock, a structural separation joint sealed with three bulb water stop is provided at the reactor building end. Most of the reactor building settlement occurred prior to construction of the railroad airlock.

The integrity of the railroad airlock doors was demonstrated by soap bubble or smoke tests. The railroad airlock was tested as part of the secondary containment capability test which is described in the Technical Specifications.

12.2.2 TURBINE BUILDING

The turbine building houses the turbine-generator and associated auxiliaries including the condensate and feedwater systems. The turbine building is a steel and concrete structure consisting of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete floors self-supporting or supported by structural steel framing.
- Reinforced concrete or concrete block interior walls.
- Reinforced concrete turbine pedestal resting on concrete mat foundation.
- Reinforced concrete (poured or prefabricated) exterior walls.
- Reinforced concrete slab on metal roof deck system supported by steel framing.

12.2.3 CONTROL BUILDING

The control building houses the common control room for HNP-1 and HNP-2 and associated auxiliaries. The building is a reinforced concrete structure with steel framing above el 164 ft. The building consists of the following major structural components:

- Reinforced concrete foundation mat.
- Reinforced concrete floors with reinforced concrete beam and girder framing.

- Reinforced concrete or concrete block interior walls and reinforced concrete columns.

- Reinforced concrete (poured or prefabricated) exterior walls.

- Reinforced concrete slab on metal roof deck system supported by steel framing.

The turbine building and control building are physically separated by radiation shield walls, fire walls, and fire doors at all levels below the operating deck. The area above the operating deck is open between the turbine building and the control building. In this area, however, the control room is protected by concrete walls on all sides; and all doors into the control room are fire doors. Equipment housed on the control room roof is protected by walls and is physically separated from any other equipment or material which would start or support a fire. An explosion or fire in the turbine building would be isolated in the turbine building and not affect operation of any of the equipment or systems in the control building.

Fires in the turbine building below the operating deck would not affect occupancy or access to the control room. Above the operating deck, the occupancy of and the access to the control room would not be affected due to physical separation and protective walls between any source of fire and the control room and the control room access route. Entrance and exit from the control room could be made by way of the stairs on the west end of the control building.

To maintain integrity of the control room atmosphere during an emergency situation, all entrances are locked. However, an airlock is incorporated at one entrance in order to prevent loss of pressure during entry or exit.

12.2.4 RADWASTE BUILDING

The radwaste building houses the equipment and control center for the liquid and solid radwaste systems which are described in sections 9.2 and 9.3. The structure is adjacent to but structurally separated from the reactor building. The radwaste building is a reinforced concrete structure.

12.2.5 RADWASTE BUILDING ADDITION

The radwaste building addition houses the equipment added to the original HNP-1 liquid radwaste system including the floor drain demineralizer. It is a reinforced concrete structure which is adjacent to but structurally separated from the radwaste building.

12.2.6 DIESEL GENERATOR BUILDING

The diesel generator building houses emergency diesel generators and their accessories essential for safe plant shutdown. It is a reinforced concrete structure. This building also houses the HNP-2 diesel generators. The diesel generator building (drawing no. H-12320) has labyrinth access openings for protection against horizontal tornado missiles.

12.2.7 INTAKE STRUCTURE

The intake structure constructed for HNP-1 is shared by HNP-2. The structure is designed to protect equipment essential for safe plant shutdown from the influence of environmental conditions such as flooding, earthquakes, and tornadoes. The following equipment is provided: coarse trash racks with cleaners, traveling screens, stop logs, plant service water (PSW) and residual heat removal service water (RHRSW) pumps. The intake structure has labyrinth access openings for protection against horizontal tornado missiles.

Safety Guide 27 sets forth design requirements in three general categories. The first category is severe phenomena listed as earthquakes (operating bases and design bases), hurricane winds, and tornadoes including tornado-induced missiles. Each of these loading conditions was added individually to the different operating loading cases. All stresses are within the limits as listed in paragraph 12.4.2.3.

Water enters the pump bay of the intake structure through two inlet bays each 9 ft 2 in. wide. (See drawing no. H-12192.) Each inlet bay is protected by a steel trash rack including a catenary trash rake and a traveling water screen. The trash rack section is separated from the traveling water screen section by a 2-ft 6-in.-thick reinforced concrete wall, and the traveling water screen section is separated from the pump bay by another 2-ft 6-in.-thick reinforced concrete wall. Water passage through these walls is by an 11-ft-high opening from the structure base slab. At normal water level, these openings are below the water level. At low water level, there is a clear opening of ~ 4 ft. The PSW pumps (four pumps per unit) and RHRSW pumps (four pumps per unit) are located in the pump bay such that if a horizontal missile did penetrate through this restricted opening, only one or two PSW pumps could be damaged. Safe shutdown requires only one PSW pump operable.

The second category of design requirements set by Safety Guide 27 is site-related events such as a transportation accident, loose barge, debris on the river, or river diversion. There is no commercial barge traffic on the river at present. However, the intake structure is protected by steel sheet pile cells from a direct hit by river traffic or debris flowing in the direction of the river channel. Traffic across the channel would of necessity be slow moving and would not damage the structure. The cells are further protected by wood fender piles to dissipate a part of the dynamic effect of a moving load. Periodic inspections and maintenance are conducted to insure an open, well-defined channel to the intake structure. A 6-ft-long by 6-ft-high extension to the center wall between the inlet bays will prevent blockage of both bays by the sinking of a barge or debris in front of the structure. River diversion has been considered and is discussed in HNP-2-FSAR subsection 2.4.9.

The third category referred to in Safety Guide 27 is single failures of manmade structural features. The inlet bays to the pump bay have been sized such that one bay can supply the water requirements for operating or for safe shutdown of both HNP-1 and HNP-2 at all river levels; thus, blockage of one bay, by any means, will not affect plant operation. The extension of the center wall between the inlet bays limits the extent of spillage in the case of failure of the upstream front sheet pile cell such that the downstream inlet bay would have sufficient clear area for water inlet even at low river water level.

The creosote wall at the intake structure was added. This new wall does not restrict the flow of water into the intake structure; it merely serves to reroute the flow, preventing undercutting of the intake structure by the river water which could cause structural damage.

12.2.8 OFF-GAS RECOMBINER

The off-gas recombiner building houses the recombiner equipment of the main condenser off-gas system. This is a reinforced concrete structure located between the turbine building and the diesel generator building.

12.2.9 WASTE GAS TREATMENT BUILDING

The waste gas treatment building houses the charcoal beds for treating gaseous radwaste. It is a reinforced concrete structure. This building is located near the main stack. This building contains equipment for both HNP-1 and HNP-2.

12.2.10 MAIN STACK

A single main stack is used to discharge gaseous waste from HNP-1. HNP-2 shares this facility. The main stack is a reinforced concrete structure 120-m high above ground level (el 119 ft 6 in.). The foundation is a reinforced concrete mat octagonal in plan supported by steel H-piles.

12.2.11 SERVICE BUILDING

The service building contains office facilities for plant management personnel and related functions. It is composed of reinforced concrete foundation and floor slab with precast concrete exterior wall panels, gypsum board on metal stud and concrete block interior partitions, and reinforced concrete roof on steel-framed metal deck.

12.2.12 WATER TREATMENT BUILDING

The water treatment building contains the well water filter and the plant makeup demineralizer. The building is prefabricated steel of rigid frame design with metal roof and siding, and reinforced concrete foundation and floor slab.

12.2.13 CIRCULATING WATER PUMP STRUCTURE

The circulating water pump structure houses the condenser circulating water pumps.

12.2.14 COOLING TOWERS

Mechanical draft cooling towers are used in the closed-loop condenser circulating water system to remove heat rejected by the main condenser. This system is described in chapter 11.

12.2.15 GENERAL DESIGN CONSIDERATIONS

12.2.15.1 Waterproofing

Building and penetration waterproofing below grade is designed to function throughout the lifetime of the plant. No formal, regularly scheduled inspection is performed, but visual checks are made for any leakage on the interior basement surfaces.

Pipes which penetrate the exterior walls of Class 1 structures below grade pass through a steel pipe sleeve which is cast into the concrete wall and projects ~ 4 in. on the inside of the building. A seal is made by welding a circular steel plate to the pipe sleeve and to the process pipe. The process pipe outside the building is coated with a bitumasite-type coating and wrapped.

12.2.15.2 Design of Class 1 Structures

12.2.15.2.1 Design Criteria

Stresses rather than deformations control the design of all Class 1 structures except for tornadoes. Deflections are computed for the various loading conditions but are in all cases elastic and substantially less than those that cause loss of function.

Elements, such as the refueling bellows around the drywell which are loaded primarily by relative displacements, are designed to accommodate the computed deformations within the allowable stress criteria.

Exterior walls are permitted to deflect up to five times the elastic deflection to dissipate the energy imposed by horizontal tornado missiles.

The structures required for safe shutdown include:

- Reactor building below the refueling floor.

- Control building.

- Diesel generator building.
- Intake structure.

12.2.15.2.2 Class 1 and Class 2 Structural Interaction

With the exception of the areas discussed below, gaps are provided between Class 1 and adjoining Class 1 and Class 2 structures so there can be free movement during an earthquake. A dynamic analysis of these structures has been performed. Relative deflections were computed for all significant modes of vibration for each structure both parallel and perpendicular to the interface. The design relative deflections were taken as the square root of the sum of the squares of the deflections. These relative displacements of Class 1 and Class 2 buildings were added directly. The results show that the gaps provided are larger than the total movement.

The gaps between Class 1 and adjoining structures were obtained by the use of 3-in.-thick foamglas. The foamglas was removed in all areas except below grade (el 130 ft) between the reactor building and its adjacent structures (control, turbine, and radwaste buildings). The design deflection at el 130 ft of each adjacent structure was calculated for the DBE using the square root of the sum of the squares method. The relative movement of two adjacent structures at el 130 ft was obtained by combining the individual deflections using the same method.

Assuming that the pressure distribution due to the foamglas was an inverted triangle, maximum at the grade level and zero at the bottom, the pressure exerted on the walls was determined assuming that the foamglas is rigid and does not deflect or crush. The combination of the maximum moment due to this triangular loading plus the other design moments in the reactor building was found to be 930 kip-ft/ft which is less than the ultimate moment capacity of 1430 kip-ft/ft. The maximum concrete stress resulting from this moment is 2530 psi, which is within the maximum permissible stress limits provided in section 12.4.

The maximum pressure calculated to be exerted on the foamglas by the relative movements of the structure was 34 psi; however, dynamic testing of the foamglas has shown that the foamglas will crush under cyclic loads of 27.8 psi. Since the calculation assumed that the foamglas did not crush or compress, then actual loads under a DBE would be less than these calculated above.

A dynamic analysis producing DBE forces was performed for the HNP-1 turbine building. Structural elements of the turbine building that could endanger the adjacent Class 1 structure and that portion having Class 1 equipment were analyzed for these DBE forces with resulting stresses less than yield. Thus, the HNP-1 turbine building is designed and constructed to ensure that it will not damage Class 1 structures or equipment located inside or adjacent to it in the event of DBE.

12.2.15.2.3 Structural Steel Strength Criteria

Two- and three-dimensional stresses are considered in the design of welds and bolted connections. Members such as beams proportioned in accordance with the interaction formula and columns subjected to axial and bending forces are provided in the American Institute of Steel Construction (AISC) Code Section 1.6. Structures not specifically covered by the AISC Code are analyzed by methods appropriate for their configuration; this furnishes a measure of the stresses the structure would experience under the postulated conditions of loadings. The referenced code was used as a guide to establish reasonable allowable stresses for these structures.

12.2.15.2.4 Structural Concrete Design Criteria

The maximum permissible stress limits for concrete and reinforcement are provided in section 12.4. The use of the working stress design method with a load factor of 1.0 gives conservative results when compared to the American Concrete Institute (ACI) ultimate strength design method. (See figure 12.2-1.)

Structures not specifically covered by the ACI Code are analyzed by methods appropriate for their configurations; this furnishes a measure of the stresses the structure would experience under the postulated conditions of loadings. The referenced code was used as a guide to establish reasonable allowable stresses for these structures.

The allowable stresses for shear, bond, and anchorage of reinforcing bars were established on the basis of ACI 318-63 Building Code. Since the plant structures are rectangular in plan and made up of beams, columns, slabs, and walls, at design loads, these elements are primarily under the action of bending moments, shears, and axial compression forces. The stress distribution in such elements is generally considered to be either uniaxial or biaxial. In establishing the stress criteria for shear, bond, and anchorage of reinforcing bars, ACI 318-63 Code has explicitly or implicitly taken the uniaxial and biaxial stress distribution into consideration.

12.2.15.2.5 Structural Adequacy of the Concrete Biological Shield

As discussed in paragraph 12.6.3.5, the concrete surrounding the drywell is capable of withstanding the indirect application of jet forces. The loadings due to thermal expansion of piping and equipment were considered in the design. Load combinations listed in paragraph 12.4.2.3 are representative of general conditions for Class I structures; and since reactions at anchor points constitute localized conditions, they were not listed.

The 2-in. air gap around the drywell is open at all penetrations and four 4-in. diameter drain pipes are provided at the bottom through the drywell shielding concrete. The air gap cannot be pressurized due to high temperature inside the drywell.

Based on a heat balance analysis for operating conditions, the expected gradient through the concrete biological shield is 70°F. This was considered in the design of the concrete and the stresses are quite low, providing sufficient margin to accommodate higher gradients. In any case, the time it takes to heat up this large mass of concrete is very long in comparison to the time at which the drywell temperature remains above 300°F; therefore, accident transients do not significantly increase the thermal gradient nor affect the concrete stresses.

As discussed in paragraph 12.6.3.5, non-axisymmetrical loads and large openings were accounted for in the analysis by using the STRESS computer program. The openings were designed as space frames to carry stresses around the discontinuities.

The design stresses are within the acceptable limits as specified in paragraph 12.4.2.3.

12.2.15.2.6 Seismic Shear for Walls

The total seismic shear in any story was distributed to the shear walls in proportion to their effective shear area. Since the height of walls in any story is constant, the distribution is also in proportion to the relative stiffness of the shear walls. For conservatism in computing affected shearing areas, only those walls parallel to the direction of seismic shear were taken into account. Each of the shear walls was designed as a deep, slender cantilever beam using an amount of reinforcement not less than that required by ACI 318-63. Allowable shearing stresses were computed by formulas 5-20 and 6-10 in Design of Multistory Reinforced Concrete Buildings for Earthquake Motions, Blume, Newmark, and Corning (pp 121 and 165).

12.2.15.2.7 Loads Imposed on Structures by Piping

The effect of a loss-of-coolant accident (LOCA) on the major piping and on the loads imposed on supporting structures by the piping was considered in the HNP-1 design. The effects are summarized as follows:

A. Pipes which are normally hot experience a decrease in temperature during a LOCA involving a blowdown and depressurization of the reactor and connected piping. This causes an increase in moments and stresses in the pipe since the pipe cools at a faster rate than the reactor vessel. This condition is governing on main steam lines. It is not governing on the feedwater lines since these lines see cooler temperatures during other transient conditions.

B. Pipes which are normally cool experience no increase in loading during a LOCA involving a blowdown and depressurization of the reactor and connected piping.

C. Pipes which are normally hot experience no additional loads during a LOCA involving a small leak which does not cause loss of reactor pressure and temperature.

D. Pipes which are normally cool experience no additional loads during a LOCA involving a small leak which does not cause loss of reactor pressure and temperature. Any heating of the pipe due to steam in the drywell relieves thermal expansion moments and stresses and loads on support structures.

These effects are considered in developing loads for supporting structures. Loads due to pipe rupture and blowdown are combined with loads due to DBE. This combination is considered a faulted condition. The structures are designed to withstand these loads without exceeding 90% of the yield strength of the material.

12.2.15.2.8 Considerations for Concentrated Loads, Concrete Crack Control, and Precast Concrete Siding Design[1][2]

Concentrated loads on slab-type elements were considered to be resisted by effective slab strips of equivalent width based on elastic theory and test results such as those given by Westergaard of the American Association of State Highway Officials (AASHO specification).

Control of concrete cracking was accomplished by providing well-distributed deformed grade 60 rebars in at least the percentages required by ACI 318-63. Pour sequences, curing, construction joints, and control joints were also designed to minimize shrinkage cracking. While torsion acts on an entire building, it is resolved into direct shear loads for the design of individual building elements in proportion to their stiffness and location relative to the center of the inertial load.

Precast concrete siding designed to meet all seismic and tornado criteria is employed. The structural steel frame is designed to withstand the loads with all siding in place.

In individual cases, an equivalent slab width for shear or bending was calculated based on the above references or a simpler, more conservative width equal to the width of the concentrated load plus twice the slab depth was used.

This approach was used in analyzing the exterior walls of the reactor building for resisting horizontal tornado missiles. The effective width of 0.58 S + 2c given by Westergaard was used, where: S = the span length and c = the diameter of the contact surface under the load. The equivalent width of wall was designed as a one-way slab spanning vertically between floors and was reinforced to carry wind and dynamic missile loads independent of constraints furnished by adjacent wall strips.

12.2.15.2.9 Steel and Concrete Supports for Pipe, Valves, and Biological Shield

For steel and concrete components of the biological shielding, pipe anchors, and valve anchors, the design criteria is as per paragraph 12.4.2.3. All the floors and other structural members were analyzed for the loads imposed by pipe supports and valve structural anchors by the following design methods:

- STRESS computer program.
- Use of engineering mechanics.

After the analysis was completed, support members were checked for the stresses and the design criteria of paragraph 12.4.2.3 were satisfied.

12.2.15.2.10 Main Steam Line Anchor Design Criteria

The governing loading condition for the main steam line anchor separating the Seismic Class 1 from the Seismic Class 2 part of the steam line is the load produced by the rupture of the main steam line.

The anchor frame is designed as a propped cantilever beam to resist the axial, lateral, bending, and torsional loads due to pipe rupture increased by 1.25 to account for dynamic effects. The anchor for these loads is designed using the maximum permissible stress limits provided in section 12.4.

12.2.15.2.11 Method of Analysis for the Following Class 1 Structures

A. Sacrificial Shield

The sacrificial shield was designed assuming the concrete has no structural strength. The seismic loads, piping loads, pipe restraint loads, platform loads, jet loads, and internal pressure generated due to a pipe break in the annulus formed by the sacrificial shield and the reactor vessel were considered in the analysis. The structure consists of 12-in. to 27-in. WF-steel columns continually tied by a 3/8-in.-thick steel plate on the inside and outside flanges of the columns from top to bottom. For seismic design, the sacrificial shield was modeled as a lumped mass spring system coupled with the reactor building, drywell, reactor vessel, and reactor vessel pedestal. A space frame model was used to derive loads in individual members for various loading combinations.

The design allowable stresses are described in paragraph 12.4.2.3.

B. Main Steam Line Enclosure

The main steam line enclosure is designed to contain main steam pipes in the event of a pipe rupture, allow proper venting for pressure increase, and reduce the radiation effects outside the pipe chase region.

In the event of a main steam pipe rupture, rigid frames are provided at midpoint in the pipe chase and at the flued head on each main steam line to prevent the pipe from whipping. The frames are supported by the walls which serve as structural support and as a radiation shield.
The controlling design loads on the walls include the pipe restraint frame reactions and a uniform pressure of 10 psi due to pipe rupture. A calculated pressure of $<$ 6 psi was determined and the analysis was performed using the Bechtel computer code COPRA. (See Containment Pressure Analysis, NS-731-TN, December 1968.)

The design allowable stresses are described in the design criteria section of paragraph 12.4.2.3.

C. Spent-Fuel Pool

The spent-fuel pool is supported by two concrete columns on one side and the drywell shield concrete on the other side. The pool floor carries a live load in addition to the water load. Two-way slab action was assumed in the slab design. Deep-beam theory was used in the wall design. Hydrodynamic effects of water and thermal effects were also included in the analysis.

Once the integrity of the system was ascertained, local stresses, embedments, connections, girder deflection, and discontinuities were investigated.

The design allowable stresses (and safety factors) are based on the ACI 318-63 working stress method. In order to minimize the possibility of pool leakage, the pools are lined with stainless-steel plate. Design and construction limitations were imposed to reduce concrete cracking.

12.2.15.2.12 Design of Reactor Pedestal

The thermal gradients, both transient and steady state, were obtained by solving analytically the Fourier differential equation of conduction in solids. For the steady state, the equation was solved through Taylor's Expansion. For the transient state, the solution was obtained by the separation of variables and a graphical method, with the transient and steady-state temperature distribution determined as described above. The thermal stresses were calculated using elastic methods for cylindrical shells. Combined stresses are within allowables presented in paragraph 12.4.2.2.

The ring girder is designed to transfer the vertical and horizontal loads of the reactor pressure vessel (RPV) skirt flange to the top of the RPV support pedestal.

The horizontal shears on the RPV skirt flange are transferred to the top flange of the ring girder by 60-A490 high-strength bolts in the same friction-type connection as is described in the AISC Code.

The amount of frictional force available to resist horizontal shear is directly proportional to the normal pressure (proof load) between the RPV skirt flange and top flange of the ring girder. The total frictional force and the coefficient of sliding friction is independent of the areas in contact, so long as the total pressure remains the same. The friction-type connection of the RPV skirt flange to the ring girder, in which some of the bolts lose a part of their clamping force (proof load) due to applied tension during an earthquake suffer no overall loss of frictional shear resistance. The bolt tension produced by the moment is coupled with a compensating compressive force on the other side of the axis of bending.

The total frictional force due to a coefficient of friction of 0.15 and a proof load of 313 kips/bolt is 2817 kips, or 2.95 times the operating basis earthquake (OBE) shear load of 955 kips, or 1.47 times the DBE shear load of 1910 kips. If the coefficient of friction is assumed zero, however, the bolts, as bearing-type connection, could resist a total horizontal shear of 6.3 (at AISC Code allowables) times the OBE shear load of 955 kips or 7.8 (at 90% yield stresses) times the DBE shear load of 1910 kips. With or without friction, the high-strength bolt connection of the RPV skirt flange to the top flange of the ring girder is more than adequate for the respective design load.

The vertical loads on the RPV skirt flange are transferred to the top of the RPV support pedestal by the ring girder acting as a bearing plate. This ring girder is designed according to AISC Code Specification.

The ring girder was fastened to the top of the pedestal by 120 2 1/4-in.-diameter A-36 anchor bolts embedded in the concrete pedestal.

The horizontal shears are transferred from the ring girder and resisted by the shear anchors welded on the anchor bolts.

The anchor bolt assembly provides a minimum safety factor of 4.5 without considering friction between the concrete and the ring girder.

The maximum calculated shear stresses at the base of the concrete pedestal under the loading combinations listed in paragraph 12.4.2.2 are within allowables.

Vertical reinforcing bars were welded on the top and bottom shear rings to prevent translation. However, bearing on the external concrete structure will also prevent translation and, therefore, no reliance on the friction factor is necessary.

The connection between the steel drywell and the concrete foundation provides a minimum factor of safety against ultimate failure of 5 and 4 for sliding and rotation, respectively.

12.2.15.2.13 Design Pressure for Penetrations

The design pressure for the portions of all primary containment penetration assemblies which comprise containment boundary is a minimum of 56-psig internal pressure and 2-psig external pressure.

12.2.15.2.14 Concrete Masonry Walls

The concrete masonry walls between cells in Class 1 structures other than containment, which are adjacent to Class 1 equipment, are designed as non-load-bearing walls. These walls are designed to withstand the earthquake forces. The seismic design basis for these walls is that found in paragraph 12.3.3.2, Design of Class 1 Structures. Load combinations are those found in paragraph 12.4.2.3, Reactor Building and All Other Class I Structures.

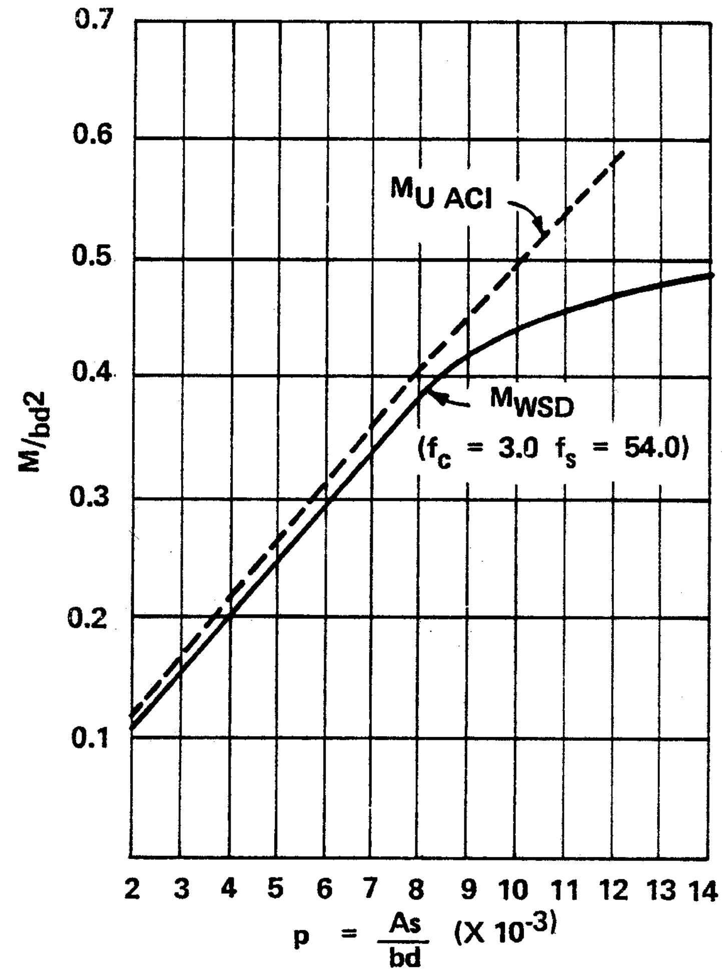
The allowable stresses for OBE are those given in ACI Committee Report 67-23, Concrete Masonry Structures - Design and Construction, ACI Committee 531, July 1970. The maximum permissible stress limits are provided in section 12.4.

The seismic loading on Class 1 masonry walls is computed in the same manner as that for buildings except that response spectrum for the appropriate floor (the one on which it is supported) is used instead of the ground response spectrum. Additional information for masonary block walls is included in subsection 12.9.1.

REFERENCES

1. Dunham, C. W., Advanced Reinforced Concrete, McGraw-Hill Book Company, pp 281-313, 1964.

2. Roark, R. J., Formulas for Stress and Strain, McGraw-Hill Book Company, pp 133-135, 1965.



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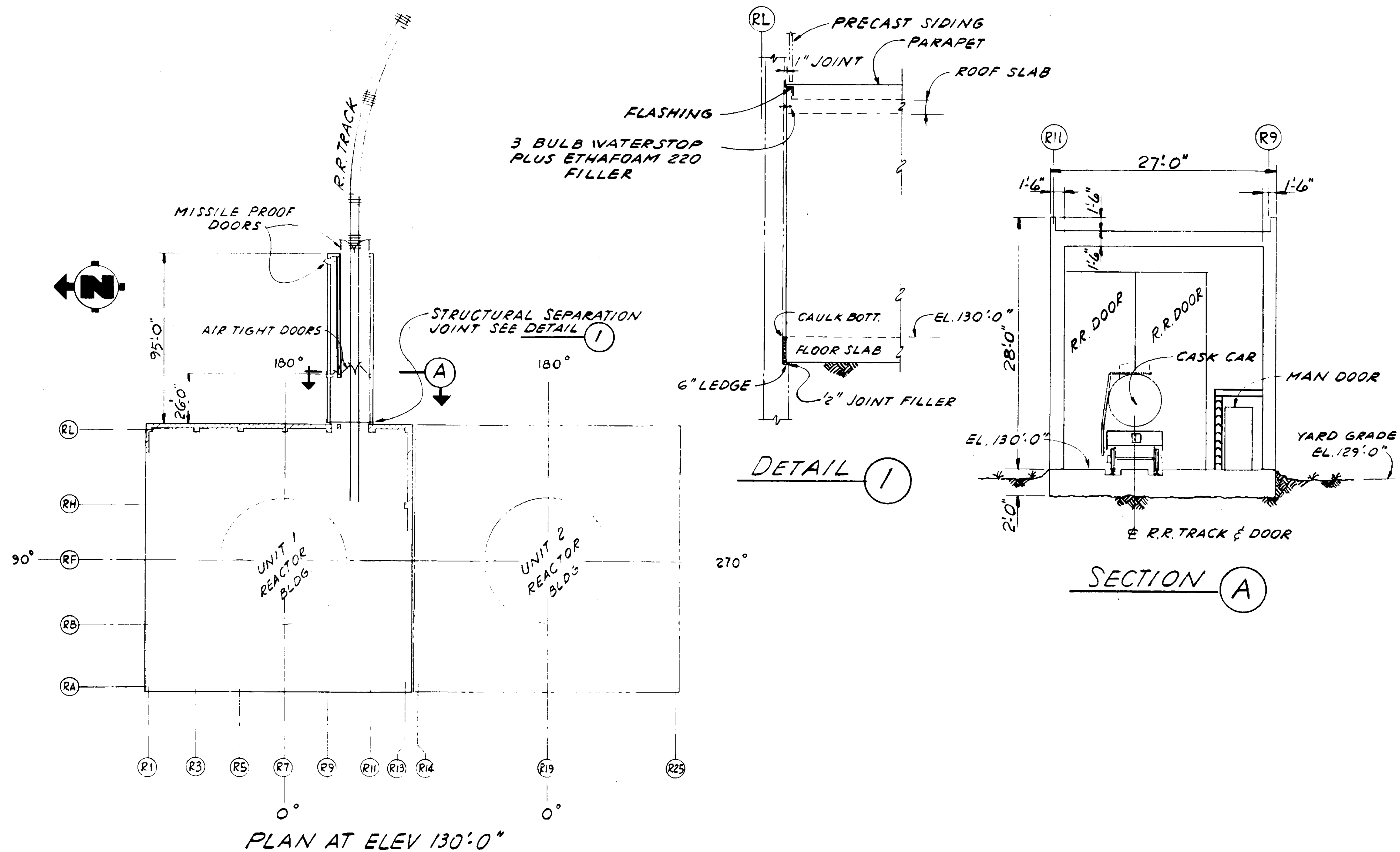
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

COMPARISON OF MOMENT CAPACITY BY ULTIMATE STRENGTH AND WORKING STRESS DESIGN METHODS

FIGURE 12.2-1



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UNIT 1

REACTOR BUILDING RAILROAD AIRLOCK DETAILS

FIGURE 12.2-2

12.3 STRUCTURAL DESIGN BASES

12.3.1 GENERAL

Certain plant structures must remain functional and/or protect vital equipment and systems, both during and following the most severe natural phenomena. These conditions are considered in the design and are investigated and defined in chapter 2, Site and Environment. Required combinations of environmental events, normal operating loads, and design accident loads for the structures are given in section 12.4.

Structures are designed in accordance with applicable codes for dead loads, live loads, seismic loads, and wind loads. Loading conditions and combinations thereof are determined by the function of the structure and its importance in meeting the plant safety and power generation objectives.

12.3.2 DEAD AND LIVE LOADS

All structures in the power plant are designed for the dead loads and live loads to which the structures are subjected. The live loads that have been used in the design of structures are given in table 12.3-1.

12.3.3 SEISMIC LOADS

12.3.3.1 Seismic Classification of Structures

12.3.3.1.1 Class 1 Structures

Class 1 structures are those whose failure might cause or increase the severity of a design basis accident (DBA) which would endanger the public health and safety. This category includes the structures and equipment required for safe shutdown and isolation of the reactor.

The following are Class 1 structures (Class 1 systems and equipment are listed in appendix A.):

- Primary containment structure.
- Reactor building.
- Spent-fuel pool.
- New-fuel storage vault.
- Diesel generator building.

- Control building.
- Intake structure.
- Main stack.
- Structures supporting or housing Class 1 equipment:
  - Wall around condensate storage tank (CST).
  - Liquid nitrogen storage tank and foundation.
  - Diesel generator fuel oil storage tanks.

12.3.3.1.2 Class 2 Structures

This class includes those structures which are important for reactor operation but are not essential in mitigation of the consequences of accidents. The failure of Class 2 structures may interrupt power generation.

A Class 2 designated structure does not degrade the integrity of any structure designated as Class 1. Although a structure, as a whole, may be Class 1, less essential portions may be considered Class 2 if they are not associated with loss of function, and their failure does not render the Class 1 portion inoperable.

The following are Class 2 structures:

- Turbine building.
- Radwaste building and radwaste building addition.
- Circulating water system including cooling towers.
- Service building.
- Water treatment building.
- Off-gas recombiner building.
- Waste gas treatment building.
- All other structures not listed as Class 1.

12.3.3.2 Seismic Design Bases

Design of Class 1 structures to withstand seismic loads is based on a dynamic analysis, using ground response spectrum curves developed for the plant site and described in chapter 2. Class 1 structures are analyzed for the following magnitudes of ground accelerations:

A. Operating basis earthquake (OBE) considers a maximum horizontal ground acceleration of 0.08 g.

B. Design basis earthquake (DBE) considers a maximum horizontal ground acceleration of 0.15 g.

C. The vertical acceleration assumed with the OBE and DBE is equal to two-thirds of the horizontal ground acceleration.

Table 12.3-2 and figures 12.3-2 and 12.3-3 define the damping factors which are used to perform the seismic analysis.

Seismic design of Class 2 structures is based on design criteria established by the Uniform Building Code (UBC) 1967 edition. The plant is designed in accordance with the UBC Zone 1 requirements. Class 2 structures are not subjected to analysis consideration of a DBE loading since safe plant shutdown is not involved.

Class 1 to Class 2 structure interfaces are designed so that there is no functional failure of the Class 1 structures due to possible failures of Class 2 structures.

12.3.3.2.1 Seismic Design Bases for Structures, Piping, Equipment, and Cable Tray Supports

Any one or a combination of the following methods have been used in the seismic analysis of Class 1 structures, piping, equipment, and cable tray supports:

- Modal analysis using either lumped- or distributed-mass models and acceleration response spectra for the points of support.[a]

- Shaker table testing of prototype components with input consisting of harmonic sine beat, or similar motions compatible with the appropriate support motion.[b]

- Use of conservative static coefficients in lieu of dynamic analysis.[c]

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a. All Class 1 structures, most cable tray supports, most piping, and some equipment, including the reactor vessel, were analyzed by this method.
b. Some equipment, primarily electrical, was analyzed by this method.
c. Some cable tray supports, piping, and equipment were analyzed by this method.

During the 20- to 30-s duration of an earthquake event, strong motion is typically experienced for 4 to 6 s. Frequencies of vibration for which the response is significant are mostly in the range from 1 to 20 Hz, with the highest responses occurring within a more narrow range, usually 3 to 8 Hz. One DBE and two OBEs are considered in the design.

The number of cycles for the DBE can be estimated by multiplying 20 Hz by 6 s by one earthquake which yields 120 cycles. Similarly, the number of cycles for the OBE can be estimated by multiplying 20 Hz by 6 s by two earthquakes which yields 240 cycles. To be conservative, the following total number of loading cycles have been used in the design:

- DBE - 300 cycles.
- OBE - 600 cycles.

There is no significant dynamic coupling between the vertical and horizontal response of buildings and floor slabs; therefore, each was computed independently. The design is based on the maximum effect of vertical and horizontal responses acting concurrently.

The horizontal amplified response loadings, which are used in the seismic design of subsystems, are obtained from time-history analyses of Class 1 buildings, the drywell, the reactor pedestal and shield, and the reactor vessel to which the subsystems are attached. The results of the time-history analysis are presented in the form of acceleration response spectra for the various elevations of the structures. These horizontal accelerations, in combination with vertical acceleration spectra equal to two-thirds of horizontal ground response spectra, are used as the seismic design input for the seismic analysis of subsystems.

12.3.3.2.1.1 **Seismic Design Bases for Structures.** See paragraph 12.6.2.1 for seismic design bases for structures.

12.3.3.2.1.2 **Seismic Design Bases for Piping.** Piping systems which are classified as flexible are analyzed dynamically by the use of a computer program which provides for the calculation of probable maximum stress, resulting forces, and probable maximum displacement in the piping system due to the earthquake ground motion effect.

The piping system is inputted to the computer program by geometrical and physical characteristics. The earthquake effect is introduced by the applicable response spectrum curves and coded for direction. To obtain the absolute maximum effect of the earthquake, two major directions of motion are considered in the analysis. An X-Y and a Z-Y earthquake are considered separately, X and Z being the two mutually perpendicular horizontal directions and Y being the vertical direction. Although the earthquake input is two dimensional for each earthquake considered, the three-dimensional effects are obtained. Figure 12.3-1 shows an example of a lumped-mass model of a piping system for seismic analysis.

The piping structure system is replaced by a lumped-mass model, and the inertia forces are induced in each mass particle. Free vibration of such a model occurs in a finite number of frequencies with particular modal shapes. The modal analysis and later synthesis allow the determination of the maximum response quantities produced in each mode and the probable maximum stress and displacement in the complex structure.

The seismic inputs to the original OBE and DBE piping system analyses were defined using the 0.5% and 1.0% damped floor response spectra, respectively. As of April 4, 1985, damping per figure 12.3-2 is used in response spectrum analyses performed for all new and replacement systems and load reconciliation work. If, as a result of using these damping values, piping supports are moved, modified, or eliminated, the expected increased piping displacements due to greater piping flexibility will be checked to assure that they can be accommodated and that there will be no adverse interaction with adjacent structures, components, and equipment. The damping criteria established by this figure are consistent with the frequency-dependent approach established by the Pressure Vessel Research Council Technical Committee on Piping Systems.(4)

The principle assumptions made in the theory of analysis are:

- Linearly elastic structure.
- Simultaneous displacement of all supports, described by single time dependent function.
- Lumped-mass model satisfactorily represents the structure.
- Modal synthesis is applicable.
- Rotational inertias of the masses have negligible effect on the deformation of the piping.

A dynamic analysis was performed on each of the 2 1/2-in. and larger Seismic Class 1 pipes for which a static analysis was previously performed. This verifies that all significant dynamic modes of response have been included.

Seismic Class 1 pipes 2 in. and smaller are restrained for earthquakes by installing vertical and horizontal restraints at precalculated standard spacings which have been developed to result in a piping system natural frequency which is higher than the significant frequencies in the building response.

For certain piping systems where the seismic response of the building or other structure to which the piping is attached is small, a simpler but more conservative static analysis was performed.

This method of analysis uses that portion of the computer program used for the dynamic analysis which computes the mass of the pipeline and the distribution of loads. Conservatism is obtained by assuming that the piping system is subject to an acceleration at all segments and at all frequencies equal to the maximum acceleration from the peak of the seismic response curve.

The determination of the systems to be analyzed statically was actually based on the magnitude of the seismic response of the building or other structure to which the piping is attached.

Valves which have extended operators are analyzed by applying a static coefficient in the most unfavorable direction to the mass of the operator and calculating the stresses in the structure of the valve considering the top works of the valve as a cantilevered beam. The stresses are required to be within the normal code allowable stress for the material without the usual increase for earthquake loads. Valves with extended operators are modeled as two masses. One is on the centerline of the pipe. The other is at the center of mass of the operator so that the torsional effect of the eccentric mass is taken into account in the seismic analysis.

For Class 1 systems which are connected to Class 2 systems, the interface between the Class 1 portion and the Class 2 portion always occurs at a valve. The analysis of the Class 1 portion includes a part of the Class 2 portion to the next anchor. The integrity of all of the piping which is analyzed with the Class 1 portion is assured by the analysis. Any failure in the unanalyzed Class 2 portion will not affect the piping on the Class 1 side of the anchor. Closure of the valve which separates the Class 1 system from the Class 2 system prevents the escape of process fluid through the failed Class 2 piping.

Class 1 systems which are not connected to Class 2 systems are investigated to assure that they are protected from damage by failure of a Class 2 system by one or a combination of the following:

- Physical separation.
- Physical barriers.
- Insufficient pressure in the Class 2 system to cause pipe motion or jet impingement or flooding which would damage the Class 1 system.
- The Class 2 system is analyzed and restrained to prevent earthquakes from overstressing the Class 2 system (treated as Class 1).

For Seismic Class 1 buried piping, the pipe was assumed fixed at the end entering a structure and extending infinitely into the soil. The horizontal and vertical movements at the entry point, resulting from the seismic analysis of the structure, were then taken as end displacements in computing the stresses.

For any Seismic Class 1 piping extending from one structure to another, the differential movements at support points of the two structures were assumed to be completely out of phase; and thus, the piping and structural stresses were computed based on the absolute sum of the two movements. Resulting stresses when combined with other operating stresses are within allowable values given in American National Standards Institute (ANSI) B31.1.0.

The locations of seismic supports and restraints for Seismic Class 1 piping 2 1/2 in. and larger, piping system components, and equipment, including snubbers and sway braces, are determined analytically and included in the seismic analysis of the piping system.

Seismic Class 1 piping 2 in. and smaller is restrained according to the design guide. The as-built drawings are then reviewed by the engineering office. Where necessary, these piping systems are dynamically analyzed using the as-built condition and modifications are made as required. The evaluations, required by Nuclear Regulatory Commission (NRC) IE Bulletin 79-14, have documented the as-built locations of Seismic Class 1 supports; and reanalyses are performed as required.

A field surveillance is conducted to ensure that the supports, restraints, etc., have been installed in the designated locations. If the as-built locations, are different from the design locations, either the locations are corrected, or the piping is re-analyzed using the as-built locations. If this analysis shows the piping to be overstressed then the restraints are relocated or restraints are added to bring the stresses within allowable stress.

12.3.3.2.1.3 **Seismic Design Bases for Equipment.** The Class 1 equipment is analyzed by applying a static seismic coefficient and calculating the resultant stresses in the equipment structure. Stresses are required to be within normal allowables.

Paragraphs C.3.2.3 and C.3.3.2, and subsection C.3.4 provide information concerning nuclear steam supply equipment. The method used to assure the adequacy for earthquake loading of Class 1 mechanical components such as pumps and heat exchangers is described in subsection C.3.4. The components in general are required to be adequate for the specified earthquake loadings without requiring additional seismic restraint. However, in the case of the residual heat removal heat exchangers, a dynamic analysis of the exchanger and its support system indicated that seismic restraint was required to prevent overloading the basic supporting steel. These restraints as well as the supporting steel were designed to resist the OBE loading without exceeding the normal allowable stresses per the American Institute of Steel Construction Code and the DBE loadings without exceeding the yield strength of the structural steel.

The static coefficients of 1.5 g and 0.14 g given in subsection C.3.4 are the values used for the design of equipment listed in table C.3-1. The actual equipment capability (which is usually considerably greater than these values) is compared with the floor response spectra. When any equipment is identified as seismically inadequate, it is modified until adequate.

All natural modes with significant seismic response are considered when evaluating equipment capability.

When using the response spectrum method of analysis, the representative maximum earthquake-induced response of interest in an SSC may be developed using the 100-40-40 percent combination rule in lieu of the square-root-of-the-sum-of-the-squares (SRSSs) method as discussed in NRC Regulatory Guide 1.92.

12.3.3.2.1.4 Seismic Design Bases for Cable Tray Supports. Cable tray supports are designed to withstand the seismic loads calculated using the floor response spectra corresponding to the locations where the supports are attached. The simultaneous application of the horizontal and vertical earthquake components creating the highest stresses are used to design the cable tray supports. Stresses are limited to allowables given in section 12.4.

In the original cable tray support analyses, the applicable damping values were established, based upon the supports' type of construction, using the values specified in table 12.3-2. As of April 4, 1985, damping per figure 12.3-3 is used for all new and replacement systems and load reconciliation work. The damping criteria specified in figure 12.3-3 provide a conservative estimate of damping for cable tray supports based on a test program.(5) As an alternative, the Seismic Qualification Utility Group (SQUG) Generic Implementation Procedure (GIP) criteria, discussed in paragraph A.3.1.4, may also be applied to new, existing, and replacement cable and conduit raceway systems.

12.3.3.2.2 Dynamic Testing Procedures

A. General Electric (GE)-Supplied Equipment

Two types of tests are used in the dynamic testing of equipment. They are discussed separately below:

1. Free Vibration Test

This test is performed on equipment whose response is dominated by the fundamental mode. The critical damping ratio and fundamental frequency are determined from this test and are used to verify or supplement calculated values used in dynamic analysis of this equipment. This test is not used alone to demonstrate dynamic capability.

In this test, an initial displacement or initial velocity is imparted to the equipment. The initial displacement is introduced by forcibly displacing the equipment and then suddenly releasing the force. The initial velocity is obtained by applying an impulse. Accelerometers or strain gauges are mounted on the equipment. After first assuring that the equipment is vibrating in its primary mode, the critical damping ratio is calculated from the logarithmic decrement.

2. Forced Vibration Test

The equipment is mounted on a shake table or driven by an eccentric shaker. The critical damping ratios, resonant frequencies, and the equipment's functional capability are determined.

The critical damping ratio of the equipment is determined by applying a sinusoidal acceleration and measuring the forced response curve (amplitude vs. forcing frequency). The critical damping ratio is then calculated by using the half-power method, fitting a theoretical forced response curve through the data points, or direct reading of the resonant amplification. The vibratory motion used is such that the vibratory loads equal or exceed the seismic loads represented by the applicable floor spectra. When testing is the only method used to demonstrate functional capability of equipment, the mounting conditions are simulated; and the equipment is operated during and after the tests.

When the seismic testing is supplemented by analysis, the seismic stresses are added to those from normal and accident conditions in the appropriate loading combinations as described in appendix C in order to assure that the equipment will perform its required safety functions. Each type of equipment is examined individually to provide this assurance.

All Seismic Class 1 equipment is qualified by either test or analysis.

B. Equipment Procured by Bechtel

The dynamic testing of Class 1 mechanical equipment is accomplished by any one of the following methods:

1. The equipment is subjected to a sinusoidal excitation, sweeping through input frequencies of 1 to 50 Hz. The input acceleration amplitudes for the forcing function is scaled from the appropriate response spectrum by a factor of 1/2 β, where: β = the estimated damping coefficient expressed as a fraction of the critical damping. The duration of the excitation is such that the equipment may be adequately excited to the accelerations shown on the response spectra.

2. The equipment is subjected to a transient sinusoidal motion synthesized by pulse exciting a group of appropriate octave filters such that the response of the shaking table and the duration of loading is a realistic and scaled response spectrum curve for the particular direction. The frequencies included in the synthesis range from 1 to 50 Hz, and the scaling is such that the equipment is excited to the given response spectrum acceleration. The duration of the test is a minimum of 10 s. The damping factor assumed for the equipment is taken in such a manner as to produce the most conservative value of equipment response.

3. The equipment is subjected to the time-history acceleration response of the particular elevation where the equipment is installed.

Equipment modules are tested individually only when the testing represents the dynamic behavior of its actual environmental operating conditions. It is required that the test demonstrate that the equipment can operate before, during, and after the specified seismic conditions at its rated or design capacity.

C. Equipment Procured by Southern Company Services, Inc. (SCS)

The limited mechanical equipment procured by SCS was seismically qualified by analyses taking into account seismic and operational vibratory loads.

12.3.3.3 Seismic Instrumentation

One recording triaxial accelerometer is installed at an appropriate location in the plant yard to measure the free field ground accelerations. These accelerations are recorded in the MCR on magnetic tape which will be available for play back following an earthquake. These records are the primary means of determining the severity of any earthquake which may be experienced.

To aid in the assessment of earthquake damage, two recording triaxial accelerometers are located in the HNP-1 reactor building; one at el 87 ft (the basement level) on the east side of the drywell pedestal and one at el 185 ft on the east side of the biological shield (the level of lateral support for the drywell and reactor vessel). These accelerometers are oriented with the major axes of the building and record on magnetic tape in the MCR.

The recording accelerometers are activated for ~ 10 s by a seismic trigger located on the ground near the free-field accelerometer. A visual signal in the control room alerts the operator that a recording has been made to preclude the possibility of miscellaneous nonseismic ground vibrations exhausting the recording tape capacity. Following an earthquake, new tapes are mounted to record any aftershocks.

Peak recording accelerometers are installed in the control building, the diesel generator building, and in the intake structure. Three peak recording accelerometers are also installed on selected components at different elevations in the Unit 1 reactor building.

The locations of the peak recording accelerometers are at points of amplified response (nonrigid) which permit evaluation of dynamic amplification factors and system damping characteristics for comparison with design values. The precise locations were determined during startup operations to ensure that the data collected is free of any operation-related influences.

A triaxial peak acceleration spectrum recording unit is provided in the Unit 1 reactor building at el 90 ft (the basement level) on the east side of the drywell pedestal. This instrument is electrically connected to an annunciator unit in the MCR and provides alarm signals to the annunciator for immediate remote indication that specific preset response accelerations have been exceeded.

This instrument consists of 12 elements in each of 3 orthogonal axes. Each element is set to respond to a vibration frequency in the range from 2 to 25 Hz. Four of the 12 elements are provided with spectrum switches which close and give remote indication when preset acceleration limits have been exceeded. The remote indication provides immediate information which could provide a basis for plant shutdown if an OBE should occur. It also provides a permanent record of data from which the response spectra may be plotted by a simple reduction process. Utilization of the data obtained from this instrument is described in paragraph 12.3.3.4.

12.3.3.4 Utilization of Data from Seismic Instrumentation

In the event of an earthquake, if the recorded acceleration at the monitoring point where the trigger is placed is greater than the triggering level, the recorded data at all accessible monitoring points will be immediately processed. An outline of the order of the actions to be taken is provided in HNP-2-FSAR figure 3.7A-7.

In the event of an earthquake, the measured responses from both the peak recording and strong motion accelerographs would be compared with those obtained in the analysis on which the design was based. If the measured responses were less than the values used in the design, the structure and equipment would be considered still adequate for future operations. However, the data would be reviewed and evaluated and the information would be used for verification of the seismic model.

Due to the random nature of an earthquake and the complexity of the structure, it would be extremely difficult, if not impossible, to establish the actual damping value of the structure within a short period of time following the earthquake. For this reason, the same conservative damping values presented in table 12.3-2 probably would be used in the new analysis.

12.3.4 LATERAL LOADS

See HNP-2-FSAR section 3.3.

12.3.5 PRIMARY CONTAINMENT LOADING CONSIDERATIONS

12.3.5.1 General

A summary of the original design basis for the primary containment system is provided in appendix K.

The primary containment system is designed to withstand all forces associated with a postulated loss-of-coolant accident (LOCA). In addition to the pressure and the thermal loading conditions shown in table 5.2-7, the primary containment is designed to withstand the jet forces associated with a LOCA. The jet forces given in table 12.3-3 are assumed to result from the impingement of steam and/or water at 300°F.

The personnel airlock design was based on the lumped mass dynamic analysis of the projecting cantilever considering the flexible support of the drywell shell in the axial and both lateral directions. The equipment hatch doors are rigidly attached to the drywell shell, and their attachment design was based on inertial forces calculated for that portion of the drywell shell. All stresses are within allowable values given in appendix K.

There are no structural connections between the equipment hatches or personnel airlock and the adjacent concrete shield that could provide a constraint on thermal or seismic movements. The drywell, including the personnel airlock and equipment hatch, is separated from the concrete by a 2-in. air gap except for the bottom area below el 111 ft 6 in. msl as described in appendix K. The connection at the drywell base is designed for the fixed condition. Local stresses for the seismic conditions were added to the stresses due to other loads, and total stress values were below the allowables.

Torus support girders were designed per ASME Section III with allowable stresses, material, and inspections in accordance with ASME Section III and stress limits for the DBE in accordance with paragraph 12.4.2.1. Columns, seismic ties, and walkways were designed in accordance per AISC with AISC allowables. Material and inspection of welds within 4 in. of torus shell are in accordance with ASME Section III. No increase in the code allowable was given when considering OBE. Stress limits for the DBE are given in paragraph 12.4.2.2.

No filler was used between the drywell and shield wall. However, a polyurethane elastic foam strip 2 1/2-in. wide x 3-in. deep with a maximum compression set of 10% and a minimum resilience of 20% was used as a sealer on each lift of concrete to prevent foreign matter from falling into the air gap during construction. No sealing strip was provided at the base transition zone. The potential for liner buckling due to the sealing strips at the construction joints is insignificant.

12.3.5.2 Flooded Containment

The primary containment is designed for a flooded condition as is indicated in the design conditions mentioned in chapter 5. The containment would not be flooded for accident recovery until a long period of time (months) after the LOCA since the containment must be vented during the flooding process to avoid over pressurization. The occurrence of either a flooded drywell (resulting from a LOCA) or a DBE must be considered unrelated events, each having a small probability. The probability of two unrelated improbable events such as these occurring simultaneously is considered to have a vanishingly small probability. Therefore, this simultaneous occurrence is not considered in the design of the primary containment.

12.3.5.3 Hydrodynamic Loads for the Suppression Chamber

In performing large scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, suppression pool hydrodynamic loads not explicitly included in the original Mark I containment design basis were identified. These additional loads could result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA, and from suppression pool response to safety relief valve operation generally associated with plant transient operating conditions. Since these hydrodynamic loads were not explicitly considered in the original design of the Mark I containment, the NRC staff requested a detailed reevaluation in early 1975 of the containment system from each domestic utility with a Mark I containment.

The Phase I effort, called the short-term program (STP), provided a rapid confirmation of the adequacy of the containment to maintain its integrity under the most probable course of the postulated LOCA considering the latest available information on the important suppression pool dynamic loads. The STP was completed July 28, 1976, following the docketed submittal by GPC to the NRC of the HNP-1 *plant-unique analysis reports.*[1] *Review of this documentation and other domestic Mark I containment plant-unique analysis reports led to issuance of the Mark I Containment STP Safety Evaluation Report in December 1977.*[2] *This report concluded that licensed domestic boiling water reactor (BWR) Mark I facilities could continue to operate safely, without undue risk to health and safety of the public, during an interim period while the long-term program (LTP) was conducted.*

The Phase II effort, the LTP, was initiated in June 1976. The LTP included detailed testing and analytical work to define more precisely the specific hydrodynamic loads appropriate for the anticipated life (40 years) of the Mark I BWR facility. It also included detailed structural evaluation and modifications to restore the originally intended design-safety margins for the containment system.

The LTP was completed in December 1983, following the docketed submittal by GPC to the NRC of the HNP-1 plant-unique analysis report.[3]

The hydrodynamic loads considered and a description of the pressure suppression chamber and drywell vent system modifications made during the STP and LTP are provided in supplement KA.

REFERENCES

1. "Torus Support System and Attached Piping Evaluations for E. I. Hatch Nuclear Plant Unit 1, Mark I Containment," Docket No. 50-321, Bechtel Power Corporation August 1976; "Torus Support System and Nuclear Plant Unit 1, Mark I Containment," Addendum 1, Docket No. 50-321, Bechtel Power Corporation, April 1977.

2. "Mark I Containment Short-Term Program Safety Evaluation Report," NUREG-0408, Nuclear Regulatory Commission, December 1977.

3. "Plant Unique Analysis Report for E. I. Hatch Nuclear Plant Unit 1, Mark I Containment Long-Term Program," Revision 2, Docket No. 50-321, Bechtel Power Corporation, December 1983.

4. Welding Research Council Bulletin Number 300: Technical Position on Criteria Establishment; Technical Position on Damping Values for Piping - Interim Summary Report; Technical Position on Response Spectra Broadening, and Technical Position on Industry Practice, 1984.

5. Cable Tray and Conduit Raceway Seismic Test Program, Release 4, Report 1053-21.1-4, ANCO Engineers, Inc., December 15, 1978.

TABLE 12.3-1 (SHEET 1 OF 2)

LIVE LOADS ON STRUCTURES

	Beams and Slabs	Girders and Columns
1. General		
Roof (minimum)	20 lb/ft^2	20 lb/ft^2
Offices	50 lb/ft^2	40 lb/ft^2
Stairways and walkways	100 lb/ft^2	80 lb/ft^2
Assembly rooms	100 lb/ft^2	80 lb/ft^2
Concentrated loads[a]	4000 lb	4000 lb
2. Turbine building		
Ground floors	350 lb/ft^2 or truck or railroad load under the hatch area	-
All floors except operating floor laydown area	200 lb/ft^2	160 lb/ft^2
Operating floor laydown area	1000 lb/ft^2	800 lb/ft^2
Grating floor and platforms	100 lb/ft^2	80 lb/ft^2
3. Reactor building (excluding drywell and torus area)		
Floor at el 130 ft		
General	600 lb/ft^2	600 lb/ft^2
In corners	250 lb/ft^2	200 lb/ft^2
Near equipment hatches	1000 lb/ft^2	1000 lb/ft^2
Near railroad airlock	Cooper E72 locomotive wheel loads	
Floor at el 158 ft, el 185 ft, and el 203 ft	200 lb/ft^2	200 lb/ft^2
Floor at el 228 ft general	1000 lb/ft^2	800 lb/ft^2
Cask area	250,000 lb (6-ft diameter)	250,000 lb (6-ft diameter)
New fuel storage area	1500 lb/ft^2	1500 lb/ft^2
Spent-fuel pool and dryer-separator Storage pool	Water plus 2000 lb/ft^2	Water plus 2000 lb/ft^2

a. For design of floor elements only. Applied at the point of maximum moment or shear. It is not cumulative and not carried to columns.

TABLE 12.3-1 (SHEET 2 OF 2)

		Beams and Slabs	Girders and Columns
4.	Drywell interior		
	Floor at el 114 ft 6 in.	200 lb/ft^2	-
	Floor at el 127 ft 10 in.	150 lb/ft^2	150 lb/ft^2
	Floor at el 148 ft 5 in.	150 lb/ft^2 plus 30,000 lb-moving load	150 lb/ft^2 plus 30,000 lb-moving load
5.	Torus area		
	Floor el 87 ft	150 lb/ft^2 or torus water load	
6.	Radwaste building		
	All floors	250 lb/ft^2	250 lb/ft^2
7.	Service building		
	Machine shop	1000 lb/ft^2	-
	Storage area	250 lb/ft^2	-
8.	Intake structure		
	Valve pit slab	200 lb/ft^2	200 lb/ft^2
	Pump room slab	200 lb/ft^2	200 lb/ft^2
	Grating floor	100 lb/ft^2	100 lb/ft^2
	Base slab	75 lb/ft^2	-
9.	Control building		
	Base slab	250 lb/ft^2	-
	All floors	350 lb/ft^2	350 lb/ft^2
	Laydown area	1000 lb/ft^2	1000 lb/ft^2
10.	Diesel generator building		
	Base slab	200 lb/ft^2	-
11.	Crane and elevator loads		

Crane and elevator loads are considered as live loads. A 25% impact increase to live load is used for traveling crane support girders and columns. A 100% impact increase to live load is used for elevator supports.

TABLE 12.3-2

DAMPING FACTORS FOR SEISMIC ANALYSIS IN PERCENT OF CRITICAL DAMPING[a]

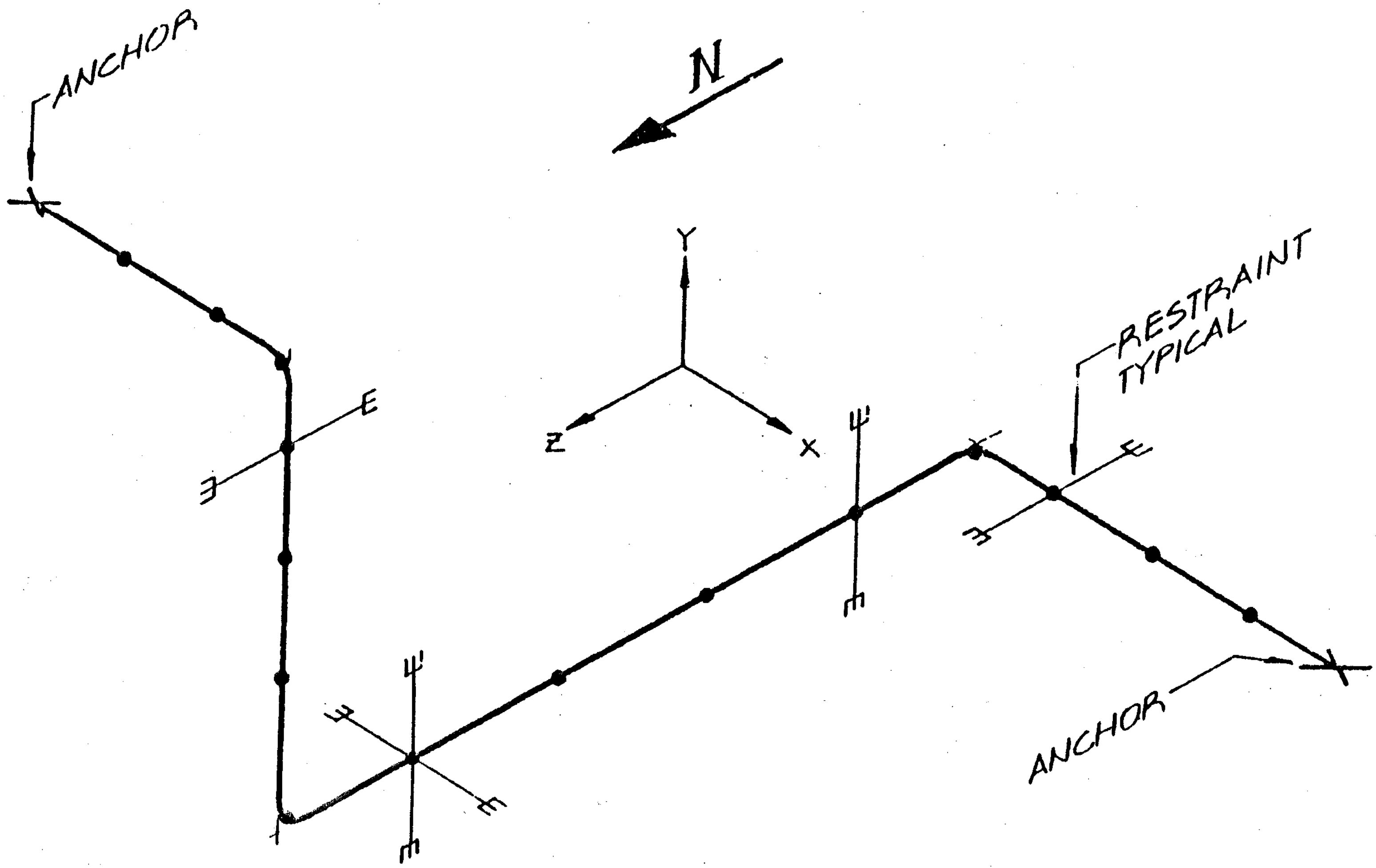
	Operating Basis Earthquake	Design Basis Earthquake
Reinforced concrete structures	3.0	5.0
Steel frame structures	3.0	5.0
Bolted and riveted assemblies	3.0	5.0
Welded assemblies	2.0	3.0
Vital piping	0.5	1.0
Translation and rotation of foundation soil	4.5	5.5

a. As of April 4, 1985, damping per figure 12.3-2 for piping systems and figure 12.3-3 for cable tray supports is used for all new and replacement systems and load reconciliation work.

TABLE 12.3-3

DESIGN JET FORCES

Location	Jet Force (kips)	Interior Area Subjected to Jet Force
Spherical part of drywell	709	3.94 ft^2
Cylindrical part of drywell and transition to sphere	472	2.63 ft^2
Closure head	32.6	0.18 ft^2
Suppression chamber	21	On each downcomer pipe



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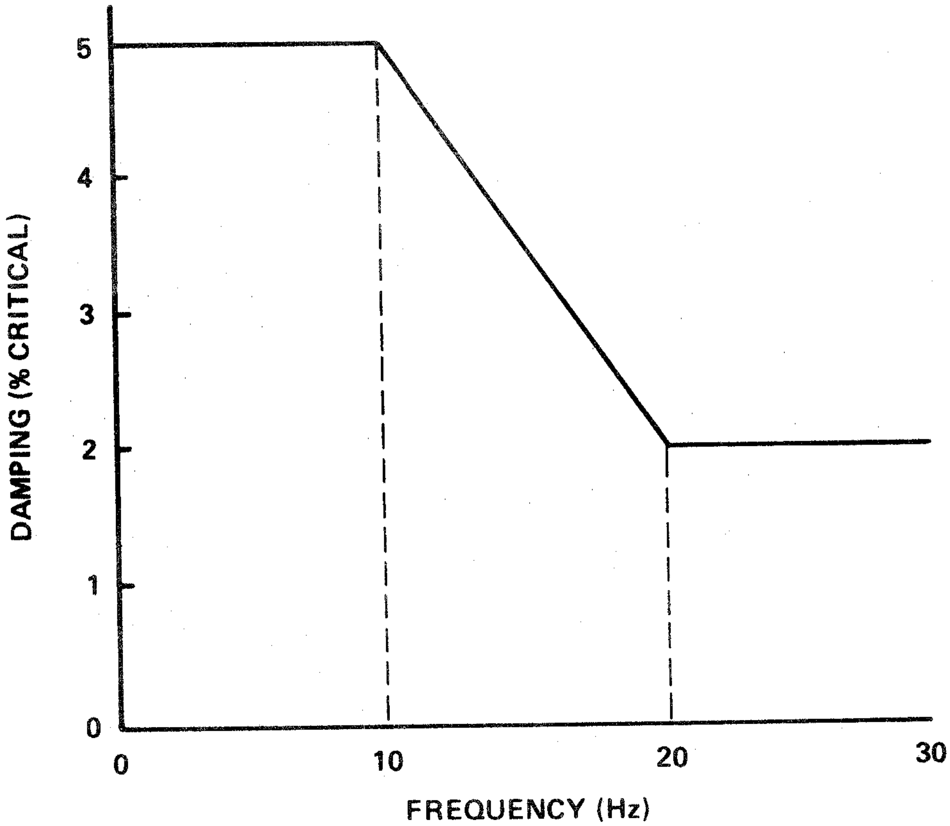
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

EXAMPLE OF A LUMPED MASS MODEL OF A PIPING SYSTEM FOR SEISMIC ANALYSIS

FIGURE 12.3-1



NOTES:

1. Applicable to both OBE and DBE, independent of pipe diameter.
2. As of April 4, 1985, damping per this figures is used for all new and replacement systems and load reconciliation work.

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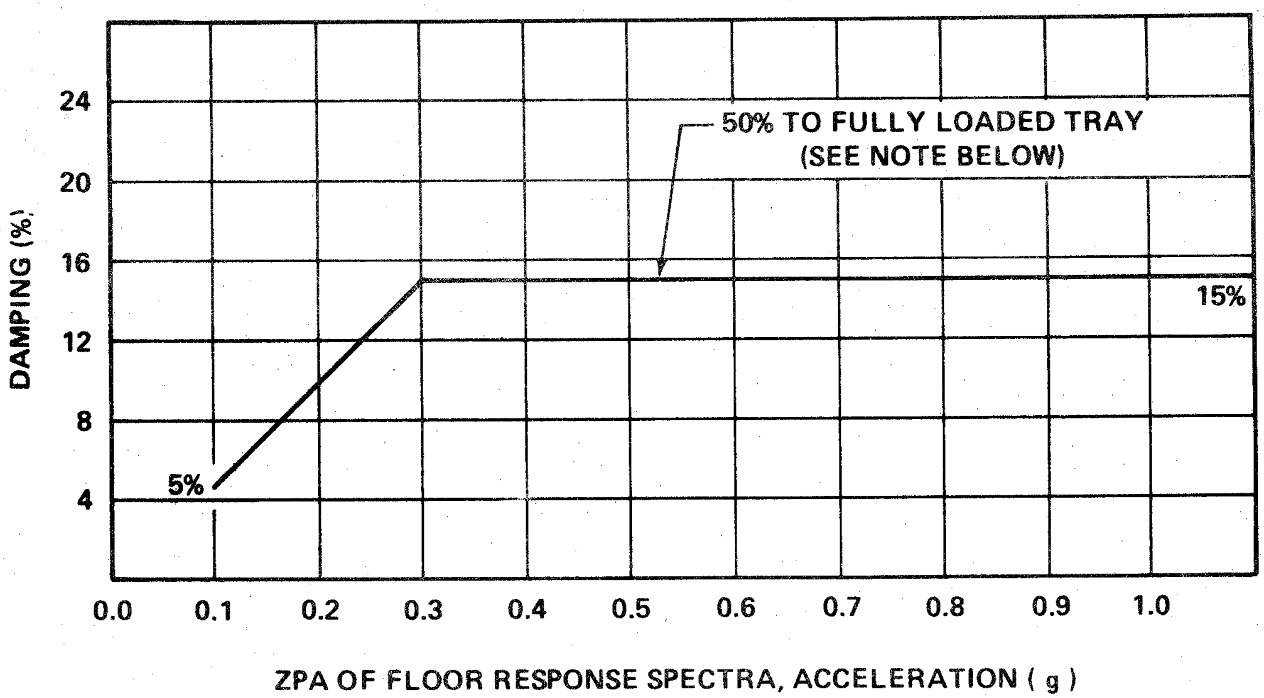
DAMPING CRITERIA FOR SEISMIC ANALYSIS OF PIPING SYSTEMS

FIGURE 12.3-2



NOTES:

1. For unloaded tray, use damping values specified in Table 12.3-2 for steel structures. For tray loaded less than 50%, linear interpolation is used to determine the applicable design damping value.

2. As of April 4, 1985, damping per this figure is used for all new and replacement systems and load reconciliation work.

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SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	DAMPING CRITERIA FOR SEISMIC ANALYSIS OF CABLE TRAY SUPPORTS
	FIGURE 12.3-3

12.4 LOAD COMBINATIONS

12.4.1 GENERAL

All the structures are designed to withstand the appropriate combinations of loads described in section 12.3.

Class 1 structure design is summarized as follows:

Load Combination	Minimum Requirements for Class 1 Structural Components
Normal loads + operating basis earthquake (OBE)	Within code allowable stresses
Normal loads + design basis loss-of-coolant accident (LOCA)	No functional failure
Normal loads + design basis earthquake (DBE)	No functional failure

In general, the design parameters are limited by codes and standards which form acceptable bases for this type of work.

The following notations are used in this subsection:

D = Dead load of structure, equipment, and other loads contributing permanent stress.

L = Live loads expected to be present when the plant is operating.

C = Crane loads.

I = Impact loads as per American Institute of Steel Construction (AISC) for crane.

H = Forces on structure or equipment due to thermal expansion of pipes or components under operating condition.

P = Pressure (except jet force) due to LOCA.

R = Jet force or pressure on structure or equipment due to rupture of any one pipe.

T = Thermal loads on structure or equipment due to LOCA.

E = OBE.

E′ = DBE.

W = Wind load.

W′ = Tornado wind load.

F = Hydrostatic loading due to post-accident flooding of the primary containment.

12.4.2 CLASS 1 STRUCTURES

12.4.2.1 Primary Containment (Including Penetrations)

		Stress Limits
A.	D+L+H+P+T+E	American Society of Mechanical Engineers (ASME), Section III, Class B, without the usual increase for seismic loading
B.	D+L+H+P+R+T+E	Same as A above, except local yielding is permitted in the area of the jet force where the shell is backed by concrete. In areas not backed by concrete, primary local membrane stresses at the jet force do not exceed 0.90 times the yield point of the material at 300°F.
C.	D+L+H+P+R+T+E′	Primary membrane stresses, in general, do not exceed the yield point of the material. The same criteria as in B above are applied to the effect of jet forces for this loading condition.
D.	D+E+F	The primary local membrane stresses do not exceed 0.9 times the yield point of the material at ambient temperature.

12.4.2.2 Reactor Pressure Vessel Support (Pedestal)

A.	D+L+H+E	Stresses remain within code allowables without the usual increase for earthquake loadings (AISC for structural steel, American Concrete Institute (ACI) for reinforced concrete).
B.	D+L+H+R+P+T	Same as A above.
C.	D+L+H+R+P+T+E	Stresses do not exceed: -150% of AISC allowables for structural steel. - 90% of yield stress for reinforcing bars.

- 85% of ultimate stress for concrete.

D.	D+L+H+R+P+T+E′	No functional failure - stresses do not exceed the yield point of the material for steel or the ultimate strength of the concrete.

The forces considered in the design of the reactor shield wall and support structure were seismic forces, dead loads, live loads, jet loads, and uniform internal pressure generated due to a complete circumferential break at the junction of the reactor vessel nozzles of any one of these lines. The reactor shield wall consists of 12 steel columns continually tied by a 3/8-in. steel plate on the inside and outside from top to bottom. The inside liner plate is connected by a complete penetration weld to column flanges. The shield wall and support structure are designed for the worst blowdown case and the stresses are allowed up to 150% of the AISC allowables for structural steel.

Heavy steel plate doors are used at the penetrations for inservice inspection. These doors are made up of steel plates up to 4 1/2-in. thick and filled with special shielding concrete to make a total thickness of 15 in. These doors are provided with door frames which transfer loads to the reactor shield wall. These doors are designed for jet forces due to a complete circumferential break of nozzle combined with pressure differential acting on the door face. To prevent the doors from becoming missiles due to these forces, they are secured by bolting to the door frame. Door frames are secured to the reactor shield wall by welded connections. The arrangement of the door for the biggest recirculation pipe (28-in. diameter) is shown in figure 12.4-1. The hinges are designed for the dead weight of the door only. The stresses are allowed up to 150% of AISC allowables for structural steel for the worst blowdown cases.

The upward thrust due to pressure buildup within the shield wall is insignificant when compared with the dead load of reactor pressure vessel (RPV). There is no net uplift for this case.

The connection at the base of the vessel was designed to resist the overturning moment due to jet load plus the maximum earthquake overturning moment; therefore, the blowdown loads due to jet alone will not cause it to move off its mounting surface.

12.4.2.3 <u>Reactor Building and All Other Class 1 Structures</u>

A.	D+L+H+E	Normal allowable code stresses (AISC structural steel, ACI for reinforced concrete). The customary increase in allowable stresses, when earthquake loads are considered, is not permitted.
B.	D+L+H+W	Code allowable stresses.
C.	D+L+H+E′	Stresses are limited to the minimum yield point.
D.	D+L+H+W′	Stresses are limited to the minimum yield point of materials as a general case. However, stresses may exceed yield point in a structural member for a missile load.

12.4.2.4 Reactor Building Crane Structure

The crane runway is an integral part of the superstructure. Its equipment and parts are designed in such a way that none will fail. The anchorage of the runway rails to the crane runway is designed to resist the horizontal and vertical forces transmitted by the crane during an earthquake. Safety clamps secure the bridge end trucks to the runway rails.

Safety clamps also secure the trolley to the bridge rails. The crane is designed for the earthquake accelerations at the level of the crane runway. The anchorage clamps and crane structure are designed for the most severe of the following:

		Stress Limits
A.	D+L+C+I	Normal code allowable.
B.	D+L+C+E	Normal code allowable without any increase for earthquake loads.
C.	D+L+C+E′	Up to yield stress for structural steel.
D.	D+L+C+W	Normal code allowable.
E.	D+L+C+W′	Up to yield stress for structural steel.

12.4.3 CLASS 2 STRUCTURES

Class 2 structures are designed in accordance with design methods of applicable codes and standards.

12.4.4 GOVERNING CODES AND REGULATIONS

The original design of all structures and facilities conforms to the applicable general codes and specifications listed below, except where specifically stated otherwise.

- Uniform Building Code 1967 (portions that apply to seismic design of Class 2 structures only).
- AISC - Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, 1963.

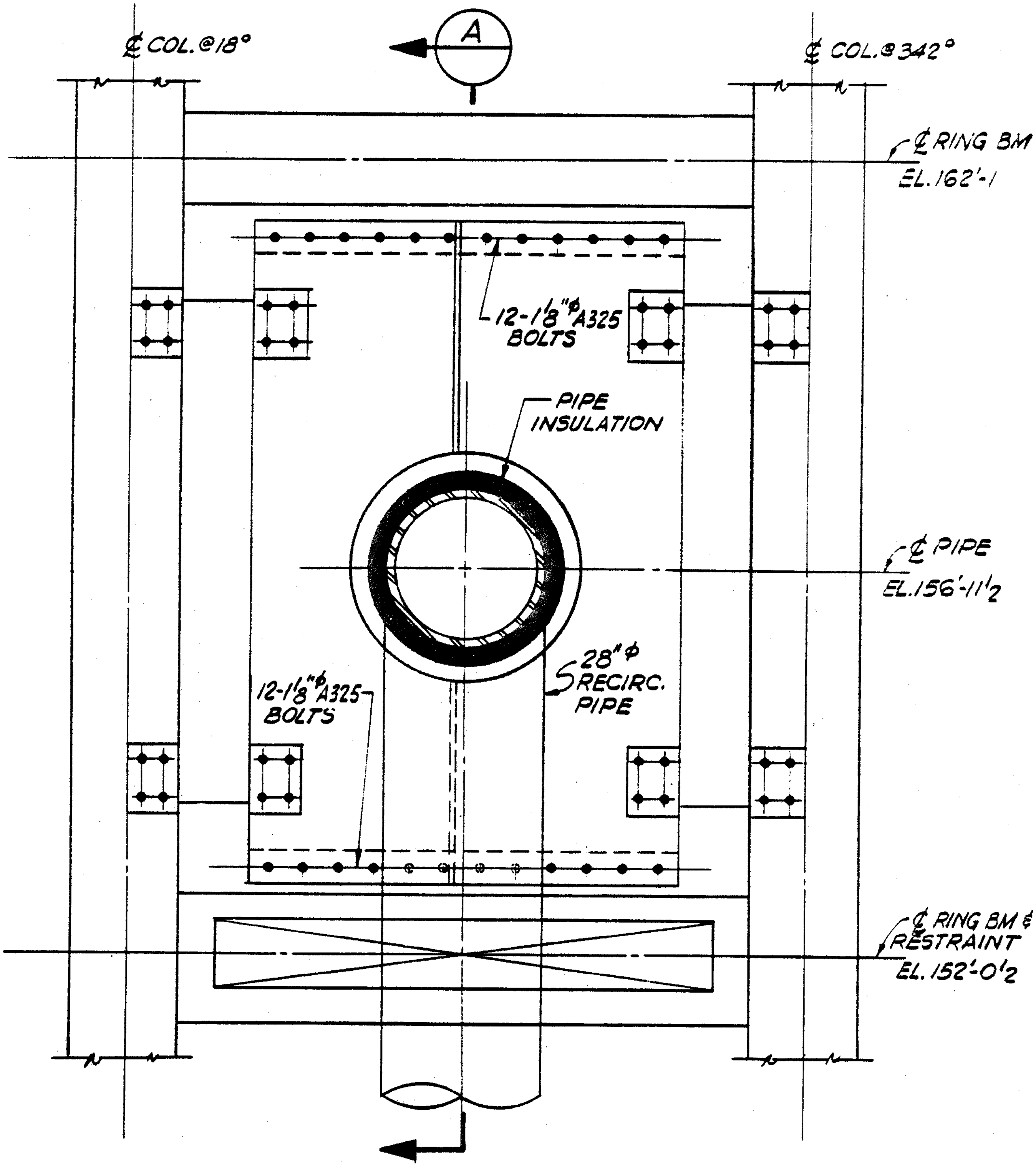
- ACI - Building Code Requirements for Reinforced Concrete (ACI 318-63) and Requirements for Reinforced Concrete Chimneys (ACI 307-69).
- American Welding Society (AWS) - Standard Code for Arc and Gas Welding in Building Construction (AWS D.1.0-66 and AWS D.2.0-66).
- NCIG-01 Rev. 2 - Nuclear Construction Issues Group (NCIG) Specifications for Visual Weld Acceptance Criteria For Structural Welding At Nuclear Plants.
- American Petroleum Institute Specification No. 650 for Welded Steel Storage Tanks.
- ASME Boiler and Pressure Vessel Code, Section III, Class B; governs the design and fabrication of the drywell and suppression chamber.
- Southern Standard Building Code.
- U.S. Army Corps of Engineers regulations with respect to dredging and construction.
- American Society of Civil Engineers Paper No. 3269 for Wind Design Requirements.[(1)]
- American Iron and Steel Institute Specification for the Design of Light-Gage Cold-Formed Steel Structural Members, 1960.

For new modifications and analysis of modifications installed after the plant was put into operation, later editions of the following codes will be used:

- AISC - Manual of Steel Construction.
- ACI - Building Code Requirements for Reinforced Concrete (ACI 318).
- ACI - Requirements for Reinforced Concrete Chimneys (ACI 307).
- American Welding Society - Standard Code for Arc and Gas Welding in Building Construction (AWS D1.0 and AWS D2.0).
- American Welding Society - Structural Welding Code (AWS D1.1).
- Southern Standard Building Code.
- Uniform Building Code.
- American Iron and Steel Institute Specification for the Design of Light-Gage Cold-Formed Steel Structural Members.

For analysis or modification of original plant designs, a later edition of the codes listed above may be used; however, the applicable sections of the original plant design codes must be reviewed. Differences between the original design codes and a later edition of these codes should be documented. Wherever a code change that is applicable to the design has occurred, a later edition of the code may be used if the change results in a more conservative design than the original design code or, the change results in an acceptable decrease in conservatism based on a better knowledge or understanding of the condition because of tests or experience by the code committee. If the code change results in a less conservative design and this change is based on a change in material quality or quality of installation, then the section from the original code edition will be used.

To account for changes in steel member properties and dimensions over the years, this information will be obtained from the AISC code edition used for the original design.



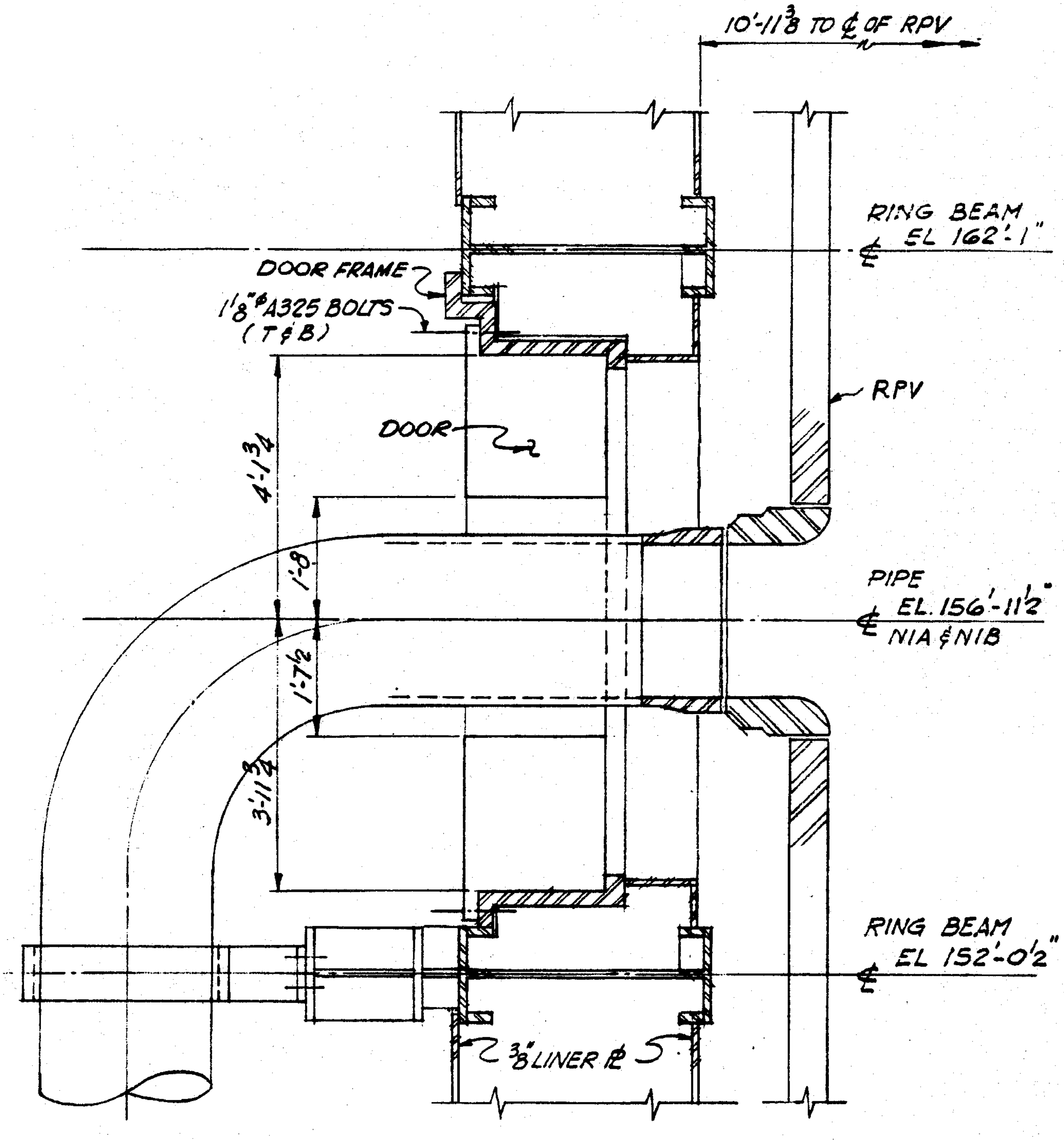
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

FRONT ELEVATION OF TYPICAL
INSERVICE INSPECTION DOOR

FIGURE 12.4-1 (SHEET 1 OF 2)



SECTION A

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

FRONT ELEVATION OF TYPICAL INSERVICE INSPECTION DOOR

FIGURE 12.4-1 (SHEET 2 OF 2)

12.5 FOUNDATION CONSIDERATIONS

The foundation scheme consists of reinforced concrete mat foundations for the reactor building, turbine building, control building, diesel generator building, and radwaste building. The foundation for the main stack is a reinforced concrete mat on steel H-piles.

The strength characteristics of the dense foundation soil and the surcharge due to the weight of the soil removed provides an excellent foundation for the plant structures. The reactor building, control building, and turbine building are founded on undisturbed soil which has a static bearing capacity in excess of 15,000 lb/ft^2.

The sub-base for the reactor building foundation slab consists of a nominal 6-in.-thick concrete slab cast directly on the finished excavation, a layer of waterproofing membrane (40-mil polyvinyl chloride), and a 12-in. concrete working slab to protect the membrane and provide a solid base for placing the foundation slab reinforcing bars.

The static coefficient of friction between the concrete and membrane is ~ 0.8 which provides a safety factor of 5 against sliding for the maximum design basis earthquake shear force.

There is no inspection plan for the foundation slab waterproofing membrane. While it is expected to last indefinitely, the 12-ft-thick foundation slab would still preclude any significant seepage in the unlikely event the membrane failed.

12.6 ANALYSIS OF SEISMIC CLASS 1 STRUCTURES

12.6.1 SCOPE

The loads, loading combinations, and allowable limits described here apply only to Seismic Class 1 structures. The criteria are intended to supplement applicable industry design codes where necessary to provide design safety margins for rare events like postulated loss-of-coolant accident or earthquakes or tornadoes.

The Seismic Class 1 concrete and steel structures are designed considering 3 inter-related primary functions for the design loading combinations described in subsection 12.4. The first consideration is to provide structural strength equal to or greater than that required to sustain the combination of design loads and provide protection to other Seismic Class 1 structures and components. The second consideration is to maintain structural deformations within such limits that Seismic Class 1 components and/or systems will not experience a loss of function. The third consideration is to limit excessive containment leakage by preventing excessive deformation and cracking where containment integrity is required.

12.6.2 STRUCTURAL ANALYSIS

In general, the structural analysis is performed utilizing the "working stress design" method as defined in American Concrete Institute (ACI) Standard Building Code Requirements for Reinforced Concrete (ACI 318-63), and in the American Institute of Steel Construction (AISC) Manual of Steel Construction (1963). Finite element stress analysis and other techniques are also used where applicable or necessary.

Load combinations and allowable limits on stresses are discussed in section 12.4.

12.6.2.1 Seismic Analysis of Structures

12.6.2.1.1 Generation of Seismic Responses for Design

The method used in the seismic dynamic analysis consists of the following four steps:

- Formulation of the mathematical model of the structure or structures to be analyzed.
- Determination of natural frequencies, mode shapes, and damping values.
- Finding the spectral acceleration (g) levels from the ground response spectra curves.

- Determination of the response of the structure to the earthquake in terms of acceleration, moments, shears, and displacements.

The mathematical model of the structure consists of lumped masses and weightless springs. At appropriate locations within the building, points are chosen to lump the mass of the structure. Between these locations, properties are calculated for moments of inertia, cross-sectional areas, and effective shear areas. These properties of the model are used in a computer program to obtain either the flexibility or inversely the stiffness properties of the building.

The mass of the structure is equally distributed to any two adjacent mass points. The masses lumped at any particular location include the mass of the building, the mass of the floor, and the masses of the equipment which are considered to be large enough to affect the response of the coupled system.

Soil and structural material properties and the bases for selection of these properties are listed in table 12.6-3. The dynamic analysis of all Class 1 structures includes the effects of the elasticity of the foundation material. Soil-structure interaction was based upon the elastic half-space theory.

The natural frequencies and mode shapes of the structures are obtained by computer programs. For example, some of the computer programs use the flexibility coefficients and lumped mass of the model. The flexibility coefficients are formulated into a matrix and inverted to form a stiffness matrix. The technique of diagonalization by successive rotations is used to obtain the natural frequencies and mode shapes. Appropriate damping values of individual materials used are presented in table 12.3-2.

The basic description of the earthquake is provided by spectrum response curves. Separate curves are used for the operating basis earthquake (OBE) of 0.08-g horizontal acceleration and the design basis earthquake (DBE) of 0.15-g horizontal acceleration. These curves are presented in figures 2.5-2 and 2.5-3. The response of the structure to the earthquake is obtained by using the spectrum response technique. Appropriate acceleration levels are read from the earthquake spectrum curve corresponding to the natural frequencies of the structure.

The mode shapes, lumped weights, and associated earthquake ground response spectrum acceleration levels are used to calculate modal responses for a given mode using standard spectrum response techniques. The total seismic response value R of interest (i.e., inertia forces, shears, moments, displacements, or accelerations) for a given earthquake component is obtained by combining the individual modal responses at a given location by the square-root-of-the-sum-of-the-squares (SRSSs) method. For example, the total response value R at mass point i is calculated using the following equation:

$$R_i = \left[\sum_{j=1}^{m} R_{ij}^{2} \right]^{\frac{1}{2}}$$

where:

R_i = total response value of interest acting at mass point i, for a given earthquake component where the response value can be either force, shear, moment displacement, or acceleration.

m = number of modes considered.

R_{ij} = response value for mass point i due to mode j.

All significant modes, including closely spaced modes, of the structural system are used for obtaining the total response. The only closely spaced modes (i.e., successive modes within 10% of each other) identified in the various analyses were the eighth and ninth modes calculated in the north-south analysis of the reactor building and internals, and the fourth and fifth and eight and ninth modes calculated in the east-west analysis of the same structure. Since these closely spaced modes contributed little to the total response of the structure, the use of the SRSSs approach to calculate total structural response was acceptable.

Table 12.6-1 lists frequency values obtained from the dynamic analyses of the reactor building, the control building, the diesel generator building, the intake structure, and the main stack.

Figure 12.6-1 shows the mathematical model used for the seismic analysis of the coupled system of the reactor building, reactor vessel pedestal with reactor shield, and the reactor vessel. The seismic moments and shears obtained from the analysis were used for the structural design of the buildings with particular emphasis on the seismic overturning, connections of the members, and arrangement of the reinforcing in the concrete. Figure 12.6-2 shows moments, shears, displacements, and accelerations for the reactor building which were used in the original design. These values were checked from time to time to evaluate the effects of the changes associated with the design development of the project, and to assure that the design values used were always conservative.

The torsional effect induced by the rotational component of the ground motion and/or the unsymmetric nature of the building was compensated for by considering a static torsional moment acting at the elevation under consideration. The magnitude of this moment is taken as the sum of the individual products of the inertia force and the eccentricity between the center of rigidity at the level of interest and the center of gravity of the mass points above that elevation.

Where uncertainties in the applicability of the elastic half-space theory or in the interpretation of the geophysical test data indicated the possibilities of significant variations from calculated frequencies, parametric analyses were made to encompass a ±50% range of expected values, and the worst cases were used for design. Also, the floor response spectra (FRS) for analysis of Class 1 equipment were conservatively plotted as smoothed upper envelopes of the calculated raw curve with peaks widened at least ±10% on each side of the expected peak frequency. Finally, the use of the smoothed-response spectra given in figures 2.5-2 and 2.5-3 preclude the possibility of serious errors resulting from expected variations between the true and calculated building frequencies.

The seismic loading on Class 1 equipment is computed in the same manner as that for the buildings except that the response spectrum for the appropriate floor or support is used instead of the ground response spectrum.

The seismic analysis of each Class 1 structure is documented in a report, including the time-history analysis and floor response spectra for analysis of Class 1 equipment. These reports are made available to all design organizations who prepare specifications for Class 1 equipment.

12.6.2.1.2 Generation of Original Floor Response Spectra

This section provides a discussion of the methodology used to develop the FRS that were used for seismic qualification of subsystems until April 4, 1985. Paragraph 12.6.2.1.3 provides a similar discussion for the development of a new set of FRS that are used, as of April 4, 1985, for subsystem seismic qualification.

The FRS were generated for inclusion in the appropriate equipment specifications and for use in subsystem design. Figure 12.6-3 shows the FRS for the reactor building floor at el 228 ft.

The FRS were generated for the OBE; FRS for the DBE were obtained by scaling up the OBE spectra in proportion to the DBE versus OBE results obtained by the response spectrum analysis. For example, the scalars for the 22 mass point reactor building model varied from 1.58 to 1.81, with an average of 1.65. A uniform scalar of 1.7 was used for all reactor building floors and all damping values.

Figure 12.6-8 shows a comparison of the smoothed-site spectra with the raw spectra developed at a maximum frequency interval of 1 Hz for the scaled 1940 north-south El Centro record. The curves are for 3% and 5% of critical damping which were generally used for the OBE and DBE analyses. Table 12.6-2 shows a comparison of maximum seismic accelerations at the 22 mass points of the reactor building model as computed by the response spectrum and time-history methods. The time-history method shows higher accelerations, because the El Centro ground spectrum is substantially above the smoothed-site spectrum. As is evident from these comparisons, the time-history analysis resulted in a substantially higher building response, as compared to the response calculated from the site spectrum.

Since there is no requirement for designing the equipment to higher seismic loads than used for the supporting buildings themselves, and since reliable methods of modifying the accelerogram were not originally available, results from the time-history analysis were scaled to acceleration levels compatible with those from the spectral analysis. Let A_i be the acceleration response at the i[th] mass point from the spectral analysis and A_i^* be the acceleration response at the same point from the time-history analysis. Then the scaling factor is defined by:

$$S_f = \frac{A_i}{A_i^*}$$

Before giving any justification for this procedure, it is noted that any motion $\ddot{Y}(t)$ may be expressed in the following form:

$$\ddot{Y}(t) = \ddot{Y}_O f(t)$$

where:

$\ddot{Y}_O$ = maximum amplitude of the motion.

$f(t)$ = time-wise variation of the motion.

Since the modal superposition method is adopted in the seismic analysis of the structure, the general equation of motion of any mode i may be expressed as follows:

$$\ddot{X}_i + 2\beta_i\omega_i\dot{X}_i + \omega_i^2 X_i = -\left[\frac{\{\phi\}_i^T[M]\{e\}}{\{\phi\}_i^T[M]\{\phi\}_i}\right]\ddot{Y}_O f(t)$$

where:

X_i = displacement at i[th] floor relative to the ground.

β_i = i[th] modal damping coefficient.

ω_i = i[th] undamped circular natural frequency.

$\{\phi\}_i$ = i[th] natural mode.

$\{\phi\}_i^T$ = transpose of $\{\phi\}_i$.

$\{e\}$ = unit vector.

$[M]$ = mass matrix of the structure.

It is apparent that the value defined by the bracket on the right side of the equation is independent of the input motion. Let X_i^* be the response of the same system corresponding to an input motion of $S_f Y(t)$ where S_f is an arbitrary scalar. Then, for a fixed damping value, there exists a linear relationship between the responses such that:

$$X_i^* = S_f X_i$$

This relationship holds for every mode considered. Now consider the total response of the system. At any time instant, the total response of a multi-degree-of-freedom system may be expressed as follows:

$$\{X\} = \ddot{Y}_O \sum_{i=1}^{n} C_i \{\phi_i\} \frac{1}{\omega_i^2} (\text{I.A.F.})_i$$

where:

$\{X\}$ = displacement vector.

n = number of masses of the structure.

C_i = i^th modal participation factor.

$(\text{I.A.F.})_i$ = i^th instantaneous amplification factor and is defined by:

$$(\text{I.A.F.})_i = \omega_i \int_0^t f(\tau) \sin \omega_i (t - \tau)\, d\tau$$

It is obvious that for a given system and a prescribed time-wise variation of the input motion, the terms inside of the summation sign will not be altered by varying the maximum amplitude of the input motion. Therefore, if the amplitude Y is multiplied by a factor of S_f, the response of the system is simply

$$\{X^*\} = S_f \ddot{Y}_O \sum_{i=1}^{n} C_i \{\phi_i\} \frac{1}{\omega_2} (\text{I.A.F.})_i \qquad \text{or}$$

$$\{X^*\} = S_f \{X\}$$

The important thing to note is that the amplitude of the vector X is modified by a factor of S_f, but the time-wise variation of the response is not changed. This leads to the fact that for a fixed damping value, the FRS generated from any floor time-history before and after the multiplication of the scalar factor S_f will have the same linear relationship S_f to each other. This indicates that the FRS generated by the scaling procedure meet the basic seismic criteria implied by the smoothed-site spectra.

Additional justification for the scaling factor (S_f) procedure, used to assure that the maximum floor accelerations from the time-history analyses were compatible with the results of the response spectrum analyses, was provided by a later evaluation. In this evaluation, the El Centro 1940 earthquake, north-south component was modified such that its resulting response spectrum envelops the smoothed-site response spectrum as shown in figure 12.6-4. This modified El Centro accelerogram was then used to generate the FRS for the identical reactor building mathematical model and member properties on which the previous time-history analysis was based. The comparison of three representative FRS for 3% of critical damping at the basement floor (el 87 ft), intermediate floor (el 158 ft), and top floor (el 228 ft) of the reactor building is shown in figures 12.6-5, 12.6-6, and 12.6-7, respectively. It is seen that all three FRS originally developed and used in the procurement of equipment enveloped at most frequencies the corresponding FRS generated from the modified El Centro accelerogram. The small portion of the curves generated using the modified El Centro accelerogram, which exceeds the FRS used to procure equipment, was insignificant. Therefore, it was concluded that the scaling factor procedure previously used is a justifiable one and that no further work needs to be done.

In plotting FRS, the effect of possible errors in building frequencies was accounted for by broadening the peaks, enveloping data points, or by using parametric analysis, as discussed in paragraph 12.6.2.1.1.

12.6.2.1.3 Generation of 1984 Floor Response Spectra

A review was performed in 1984 that addressed the FSAR peak-broadening requirements of the FRS, and it was concluded that no significant safety issue exists with the subsystems that were seismically qualified using the original FRS discussed in paragraph 12.6.2.1.2. In the process of performing the review, new (1984) FRS were developed to reflect the as-built condition of the structures and provide a more realistic representation of the specified seismic design environment (i.e., ground design response spectra, as given in figures 2.5-2 and 2.5-3).

The 1984 FRS are used, as of April 4, 1985, to seismically qualify subsystems. The following is a discussion of the techniques used to develop these FRS.

The time-history approach was used to generate the new FRS. Instead of increasing the OBE spectra by a factor to obtain the DBE spectra, FRS were developed separately for the OBE and the DBE. Separate synthetic time histories were developed for use in generating the OBE and DBE spectra. Figure 12.6-9 is a plot of the response spectrum of the OBE synthetic time history compared with the OBE ground design response spectrum for 3% critical damping. Similarly, figure 12.6-10 is a plot of the response spectrum of the DBE synthetic time history compared with the DBE ground design response spectrum for 5% critical damping. Comparison of these figures with figure 12.6-8 demonstrates that the two new synthetic time histories provide a more realistic representation of the seismic ground design response spectra than does the El Centro time history used to develop the original FRS.

Since the new synthetic time histories provide a more realistic representation of the seismic ground design response spectra than does the El Centro time history, no scaling factor (S_f), as discussed in paragraph 12.6.2.1.2, was used.

The 1984 FRS were developed at the same mass points as the original FRS and were plotted separately for the north-south and east-west directions. In plotting FRS, the effect of possible errors in building frequencies was accounted for by broadening the peaks, enveloping data points, or by using parametric analysis, as discussed in paragraph 12.6.2.1.1. Examples of the 1984 FRS are shown in figures 12.6-11 through 12.6-14.

12.6.2.2 Tornado Analysis of Structures

Appropriate portions of the plant are designed to withstand the effects of a tornado as defined in section 12.3.

The exterior walls of the reactor building are selected as representative of the design procedure. Using a model of the building and normalized Hoecker pressure profile, suctions and airflows within the building were computed using the principles of compressible fluid flow. A maximum transient crushing and bursting pressure of 292 lb/ft^2 and 136 lb/ft^2 was computed. These were applied to the walls as uniform loads to develop moment and shear diagrams. Additionally, the exterior walls were designed for dynamic concentrated loads representing the tornado missile impacts. These loads were obtained from dynamic analysis of the walls subjected to a pulse loading. The pulse was fitted to each case (i.e., span length, thickness and horizontal missile energy) by trial and correction to satisfy energy and momentum principles. The moments and shears due to horizontal missiles were combined with those from crushing. The bursting moments and shears, or carryover moments from missile impact, if larger, were used to design the opposite face reinforcement.

In most cases, practical wall designs required a portion of the horizontal missile impact energy to be dissipated in the plastic range in the struck span. The ductility ratio as a general rule was limited to 10. This ratio in no case exceeds 20.

12.6.3 IMPLEMENTATION OF STRUCTURAL CRITERIA

This subsection illustrates the loads and load combinations and structural static and dynamic analysis used in the structural design of Seismic Class 1 structures and briefly discusses typical structural elements of the reactor building and summarizes the actual stresses in these elements.

Design procedures used for the reactor building were also used for the other Seismic Class 1 structures, such as the diesel generator building, the control building, and intake structure. The main stack is designed to meet design criteria of Seismic Class 1 structures except for tornado loading.

12.6.3.1 Reactor Building Floor System

The reactor building floor system consists of variable slab thickness on permanent cold formed steel decking supported by composite steel beams girders and columns. Interior and exterior walls above grade are generally nonload bearing.

The floor system is designed to support dead loads, equipment loads, laydown loads, piping loads, live loads (table 12.3-1), and vertical seismic loads based on DL + .25 LL. Additionally, exterior panels are designed to resist moments due to the tornado load on adjacent exterior walls and the horizontal shear due to lateral seismic forces. Slabs are thickened locally to provide radiation shielding.

The slabs range in thickness from 12 in. to 54 in. and are generally designed as one-way continuous slabs in accordance with ACI 318-63. In thick slabs, where temperature reinforcement exceeded that for stresses, 0.18% rebar was placed each way in each face.

Most of the steel beams and girders are designed as composite sections in accordance with American Institute of Steel Construction using 7/8-in.-diameter shear studs. While most of the supporting columns are encased in concrete, they were conservatively designed as unencased. Also, the customary live-load reduction for lower story columns was neglected.

The structural steel frame was generally designed only for vertical loads since the concrete shear walls provide lateral resistance. However, exterior columns were checked for stability in the deflected configuration that would result from a horizontal tornado missile impact. The loading combinations, resulting stresses, and allowable stresses are tabulated in table 12.6-4.

12.6.3.2 Reactor Building Concrete Wall

The east wall of the reactor building is selected to illustrate the implementation of the design criteria. This wall experiences several loading combinations. It is a shear wall for the seismic forces due to an earthquake (E or E') in the north-south direction. In substructure, it serves as a basement wall and experiences soil and hydrostatic loads. In the superstructure of the reactor building, this wall is designed to withstand normal wind loads (W), as well as tornado loads (W'). The combination of these loads is critical for the design of the east wall. The governing design conditions, design stresses, and allowable stresses are tabulated in table 12.6-5. The design stresses are within the allowable limits.

12.6.3.3 Reactor Building Roof Structure

The reactor building roof structure consists of seven rigid steel bents braced in the north-south direction supporting a 5-in.-thick concrete roof deck and 8-in.-thick precast concrete wall panels. The bents, consisting of 36-in. rolled columns and 10-ft-deep trusses, also provide lateral support for the 125-ton overhead crane. Vertical crane loads are carried by separate crane columns.

Controlling design loads include dead load, 20 lb/ft^2 live load, and seismic and tornado loads. The 300-mph tornado wind is resisted within the elastic range with all wall panels in place. Vents in the roof are provided that will fail at 55 lb/ft^2 to partially relieve tornado-induced bursting pressures.

12.6.3.4 Reactor Pedestal

The reactor pedestal was investigated for various loads: dead load (D), live load (L), earthquake (E or E'), temperature (T) associated with an accident condition for a horizontal thermal gradient of 48°F and a vertical thermal gradient of 84°F, and jet forces (R) associated with a pipe rupture. Jet forces on pipe restraints attached to the reactor shield and pedestal were also investigated. The overall design was based on very conservative assumptions to allow for the complex interactions of the various loads.

12.6.3.5 Drywell Shielding Concrete

The drywell shielding concrete has an irregular shape. This structure was analyzed by the stress computer program for non-axisymmetrical loads. For this analysis, the structure was modeled as a space frame. For all axisymmetrical loads, the structure was analyzed by the finite element computer program. The results of these programs were combined for checking maximum stress values. The structure was made thicker around large openings such that the stresses were within the acceptable limits.

The drywell shielding concrete is not subjected to tornado loads (W'), wind loads (W), or jet forces (R). The indirect application of jet forces (R) was investigated as a special case. The concrete is capable of withstanding the jet forces, as a localized load, should the drywell yield locally without rupture and close the 2-in. air gap between the drywell and the shield.

The design stresses under all loading combinations are within the allowable limits.

TABLE 12.6-1

NATURAL FREQUENCIES OF STRUCTURES FOR EAST-WEST DIRECTION (Hz)

Mode No.	Reactor Building	Control Building	Diesel Generator Building[a]	Intake Structure	Main Stack
1	0.67	1.01	4.12	7.04	0.60
2	3.21	5.38	7.76	21.13	2.24
3	4.25	7.00	36.20	35.32	4.88
4	6.66	11.07	-	44.41	8.14
5	7.54	15.27	-	53.74	11.66
6	10.47	22.19	-	69.32	15.22
7	14.95	30.70	-	-	18.57
8	20.07	40.06	-	-	21.26
9	21.57	-	-	-	24.52
10	27.44	-	-	-	26.63
11	-	-	-	-	31.36

a. The diesel generator building natural frequencies are those associated with the mean soil properties for this building.

TABLE 12.6-2

COMPARISON OF MAXIMUM SEISMIC ACCELERATIONS FOR REACTOR BUILDING

	Acceleration (g)	
Mass Point	Response Spectrum Method	Time-History Method
1	.080	.121
2	.098	.151
3	.126	.177
4	.168	.210
5	.188	.243
6	.218	.293
7	.066	.092
8	.071	.075
9	.085	.094
10	.081	.133
11	.089	.143
12	.101	.154
13	.123	.170
14	.194	.251
15	.096	.148
16	.118	.170
17	.133	.185
18	.174	.218
19	.136	.189
20	.232	.316
21	.304	.440
22	.385	.573

TABLE 12.6-3 (SHEET 1 OF 2)

SOIL AND STRUCTURAL MATERIALS PROPERTIES

Material	Use or Location	Properties	Bases
Foundation soils	Reactor building	Shear wave velocity 2450 ft/s	From site geophysical testing by Law Engineering Company
		Compression wave velocity 6600 ft/s	
		Poissons ratio 0.42	
		Young's modulus 66,200 ksf	Computed by elastic theory from Vs and Vc
		Shear modulus 23,300 ksf	
		Unit mass 0.0039 k-s^2/f	Assumed
		Horizontal spring 1.04 x 10^7 kpf	Computed from elastic half-space theory with equations presented by Barkan and Parmalec
		Rocking spring 7.2 x 10^{10} kf/rad	
		Damping	Table 12.3-2

The properties listed above were also computed for all other Class 1 and adjacent Class 2 structures. Properties varied due to location depth and geometry of the foundation.

TABLE 12.6-3 (SHEET 2 OF 2)

Material	Use or Location	Properties	Bases
4000 psi concrete with Grade 60 reinforcement	General plant	Young's modulus 526,000 ksf	ACI 318-63
		Shear modulus 210,000 ksf	Assumed = 0.4E
		Unit mass 0.0047 $\frac{k\text{-}s^2}{f}$	Assumed
		Damping	Table 12.3-2
ASTM A36 structural steel	Platforms, columns, and roof structure	Young's modulus 4,176,000 ksf	Assumed
		Shear modulus 1,670,400 ksf	Assumed
		Unit mass 0.0154 $\frac{k\text{-}s^2}{f}$	
		Damping	Table 12.3-2

TABLE 12.6-4

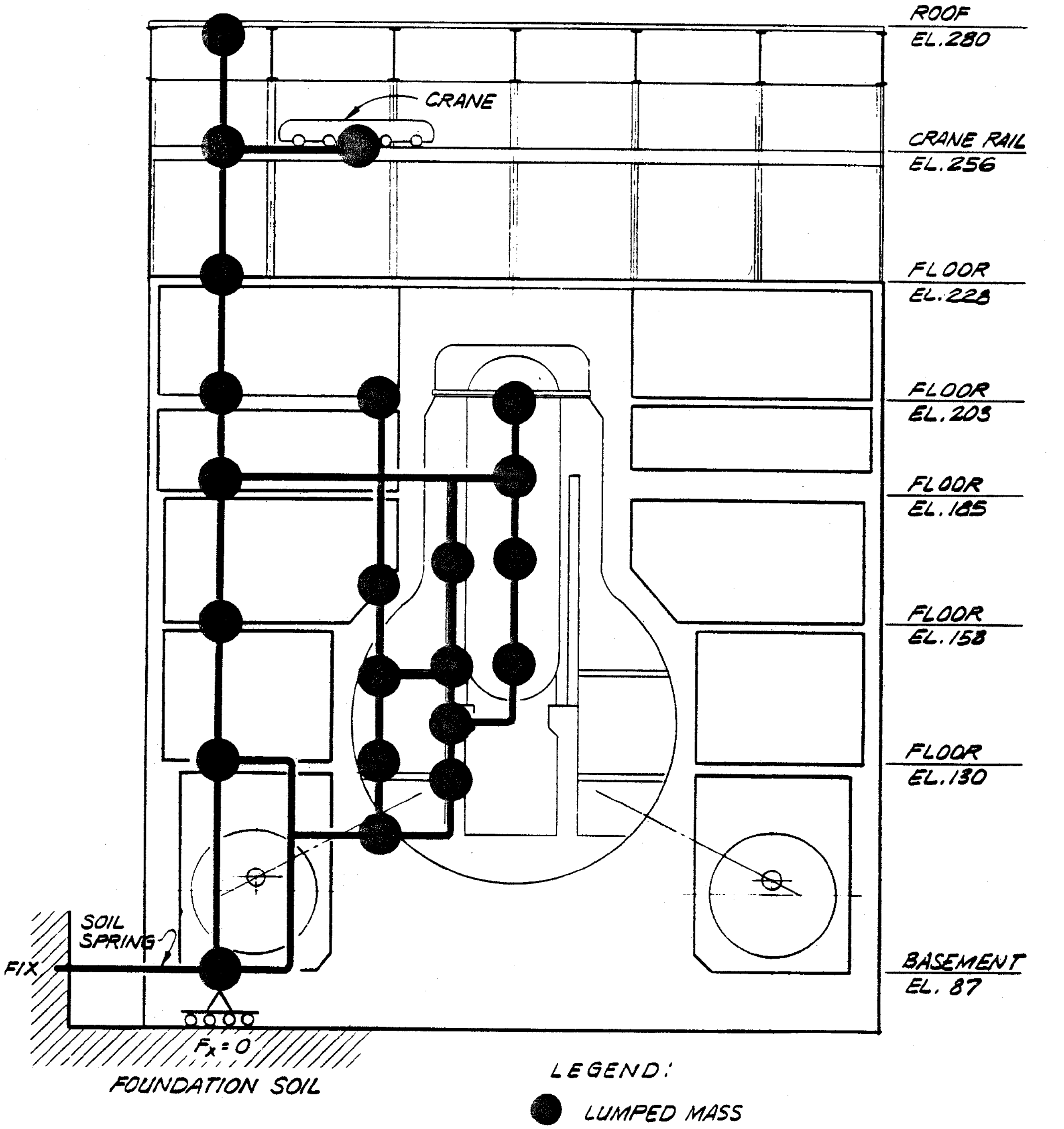
REACTOR BUILDING FLOOR SYSTEM

Element Location Description	Criteria	Method of Analysis	Load and Load Combination	Allowable Stresses	Actual Stresses
Floor slab: NE corner at nominal el 185 ft 0 in. between column lines R3 and R5. Nominal 1-ft 0-in. thick slab spanning 10 ft 3 in.	Working stress Design concrete: ACI 318-63 f'_c = 4000 psi Reinforcing: ASTM A615-68 Grade 60 F_y = 60 ksi	Continuous one-way slab analyzed using moment distribution method	D = Weight of concrete and/or beams + equipment and walls L = 2000 lb/ft E = 0.06 (D + .25L) vertical	f_c = 1800 psi f_v = 70 psi f_s = 24 psi Bond = 216 psi (#8 bars)	Positive moment: f_c = 387 psi f_s = 9050 psi Negative moment: f_c = 256 psi f_s = 10,050 psi f_v = 18 psi
Floor beam: NE corner at nominal el 185 ft 0 in. between column lines R3 and R5 20 ft 6 in. from column line RL. Composite 24 WF 76 with 54 7/8 in. x 5-in. long shear studs (Beam E)	AISC Manual of Steel Construction, Section 1.11, 1963, ASTM A36 Steel	Simple span composite steel and concrete beam	D + L + E plus 4^k concentrated load located at point of maximum moment and of maximum shear for floor beam design	F_b = 24 ksi F_v = 14.5 ksi F_c = 1800 psi	f_b = 12.4 ksi f_v = 10.2 ksi f_c = 500 psi
Column: Column R5, RL between el 185 and el 158 14 WF 605 KL = 23 FT $\frac{L}{R_x}$ = 36 $\frac{L}{R_y}$ = 61	ASIC Manual of Steel Construction, Section 1.6, 1963 Edition	Satisfy interaction formula for combined axial load and bending moments about both axis. Neglect added capacity due to concrete encasement. Use K = 1.0	D + L + E P = 1814 kip M_x = 340 in-kip M_y = 0 C_m = 0.6	F_a = 17.33 ksi F_b = 24.0 ksi Formula 7a and 7b ≤ 1.0	Formula 7a gives 0.69 Formula 7b gives 0.62
		Also check column stability in deflected position resulting from horizontal tornado missile impact causing 5-in. deflection	Same as above plus the moment due to 5-in. eccentricity of the vertical load	F_a = 25 ksi F_b = 32 ksi Formula 7a and 7b ≤ 1.0	Formula 7a gives 0.59 Formula 7b gives 0.68

TABLE 12.6-5

REACTOR BUILDING CONCRETE WALLS

Element Location Description	Criteria	Method of Analysis	Load and Load Combination	Allowable Stresses	Actual Stresses
Superstructure: East wall elevation between el 130 ft 0 in. to el 158 ft 0 in. and between column line lines R3 and R5	Concrete: ACI 318-63 f'_c = ′4000 psi at 28 days	Analyzed as a one-way continuous slab using the theory of plastic collapse	W′ = 300 mph wind + 4000-lb horizontal missile traveling 50 mph	f_c = 0.75 f'_c = 3000 psi f_t = 0.90 F_y = 54 ksi	Sufficient capacity provided to limit ductility ratio to 5 at point or horizontal missile impact
	Reinforcing: ASTM A615-68 Grade 60 F_y = 60 ksi	One-way continuous slab; elastic theory	W = 105 mph wind	f_c = 1800 psi f_t = 24 ksi	Does not control
		Shear wall Structural Design for Dynamic Loads, Norris <u>et al</u>. V_a = .04 f'_c LT V_a = .09 f'_c LT	E E′	V = 5900 kip V = 13200 kip	V = 1980 kip V = 3120 kip
Substructure: Exterior wall below grade	Concrete: ACI 318-63 f'_c = 4000 psi at 28 days Reinforcing: ASTM A615-68 Grade 60 F_y = 60 ksi	Continuous two-way vertical slab with support points at corners, diagonal walls, and base slab. No support assumed at top during construction. Assumed pinned at top after floor at 130 ft are completed.	Hydrostatic + soil + surcharge + E	f_c = 1800 psi f_s = 24 ksi	f_c = 1500 psi f_s = 22400 psi
			Hydrostatic + soil + surcharge + E′	f_c = 3400 psi f_v = 188 psi f_s = 38 ksi	Does not control



MATHEMATICAL MODEL
FOR E.W. & N.S. ANALYSIS

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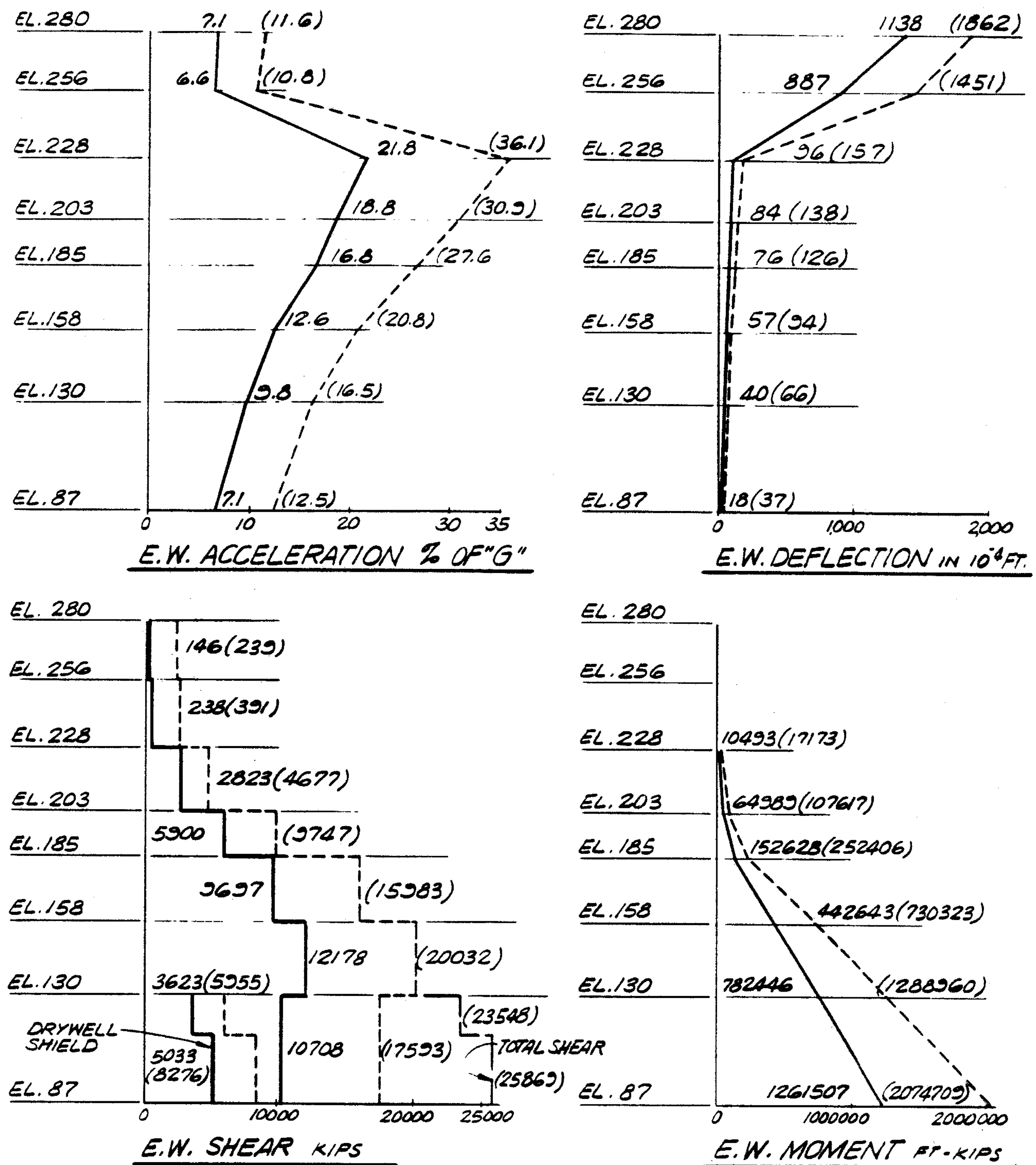
REACTOR BUILDING MATHEMATICAL MODEL

FIGURE 12.6-1



N = OPERATING BASIC EARTHQUAKE
(N) = DESIGN BASIS EARTHQUAKE

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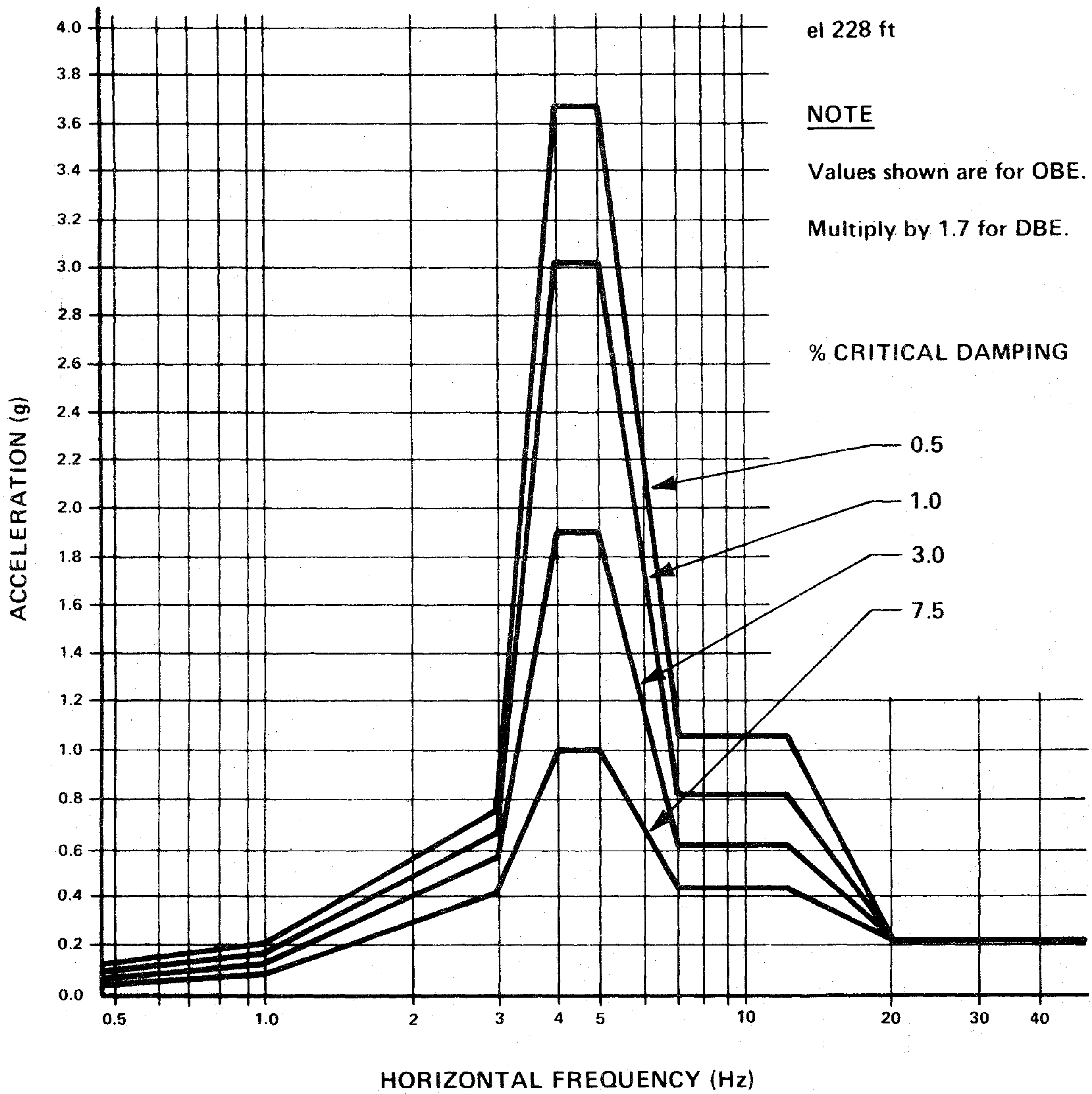
REACTOR BUILDING RESULTS OF SEISMIC ANALYSIS

FIGURE 12.6-2



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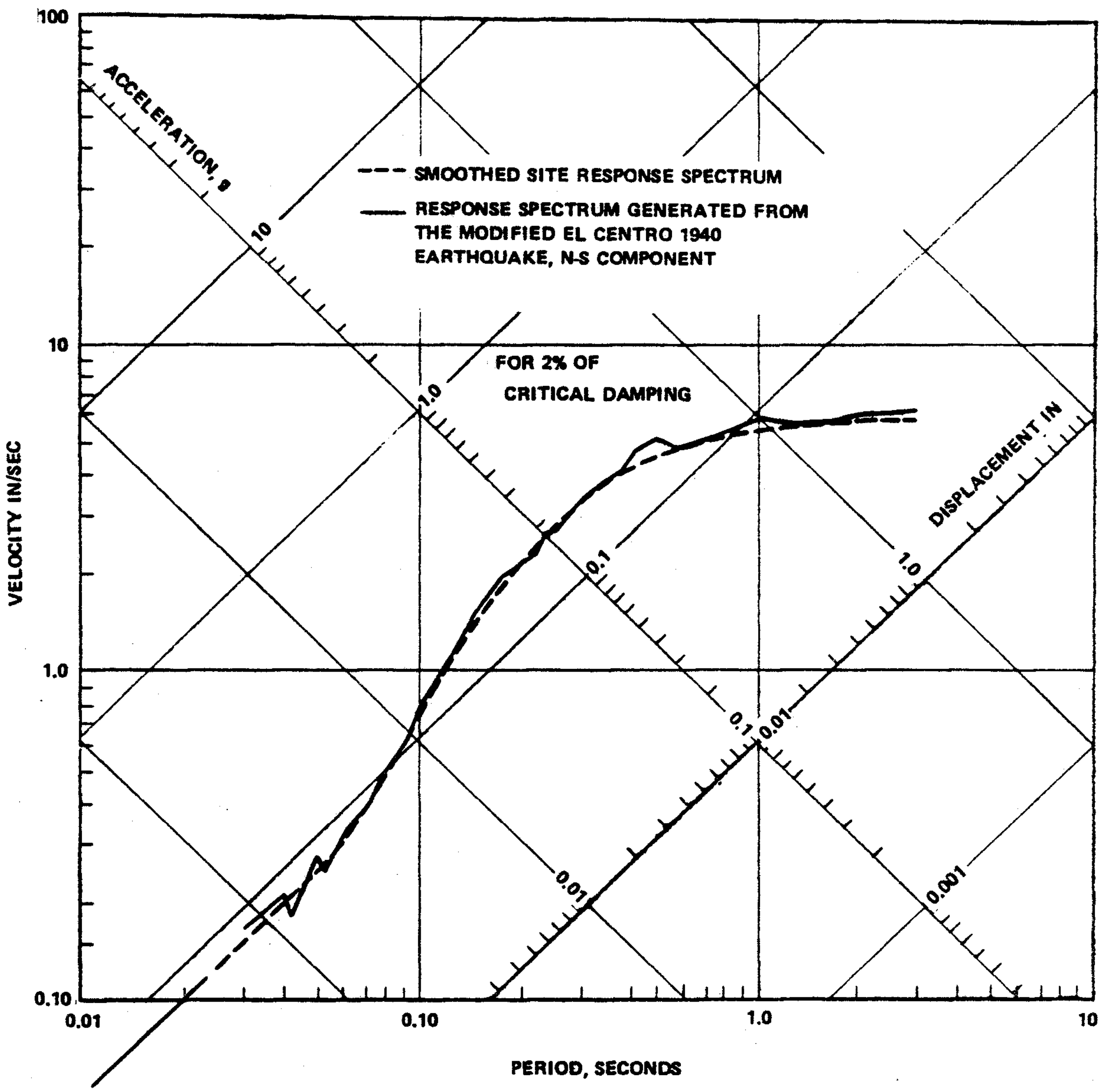
REACTOR BUILDING RESPONSE SPECTRA FOR FLOOR AT el 228 ft

FIGURE 12.6-3



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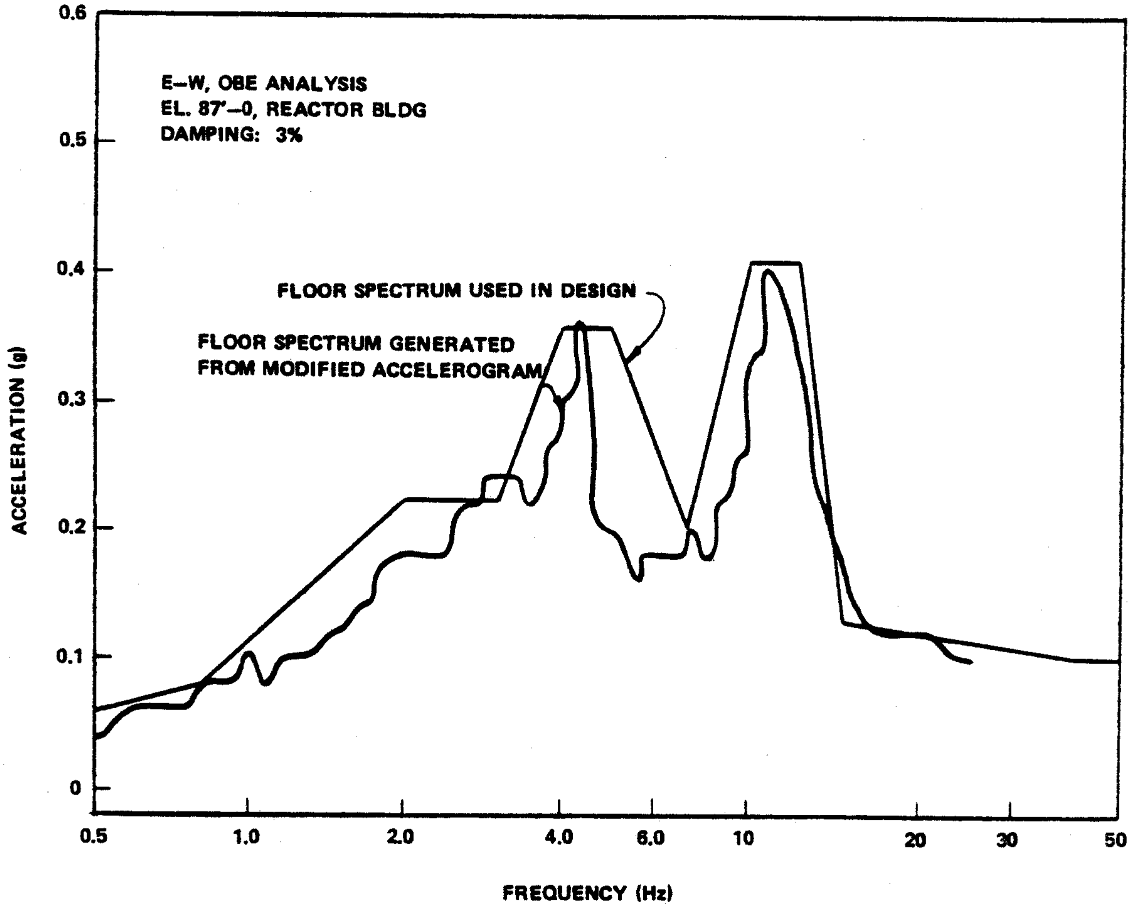
COMPARISON OF THE SITE SPECTRUM AND RESPONSE SPECTRUM OF THE MODIFIED EL CENTRO 1940 EARTHQUAKE N-S COMPONENTS

FIGURE 12.6-4



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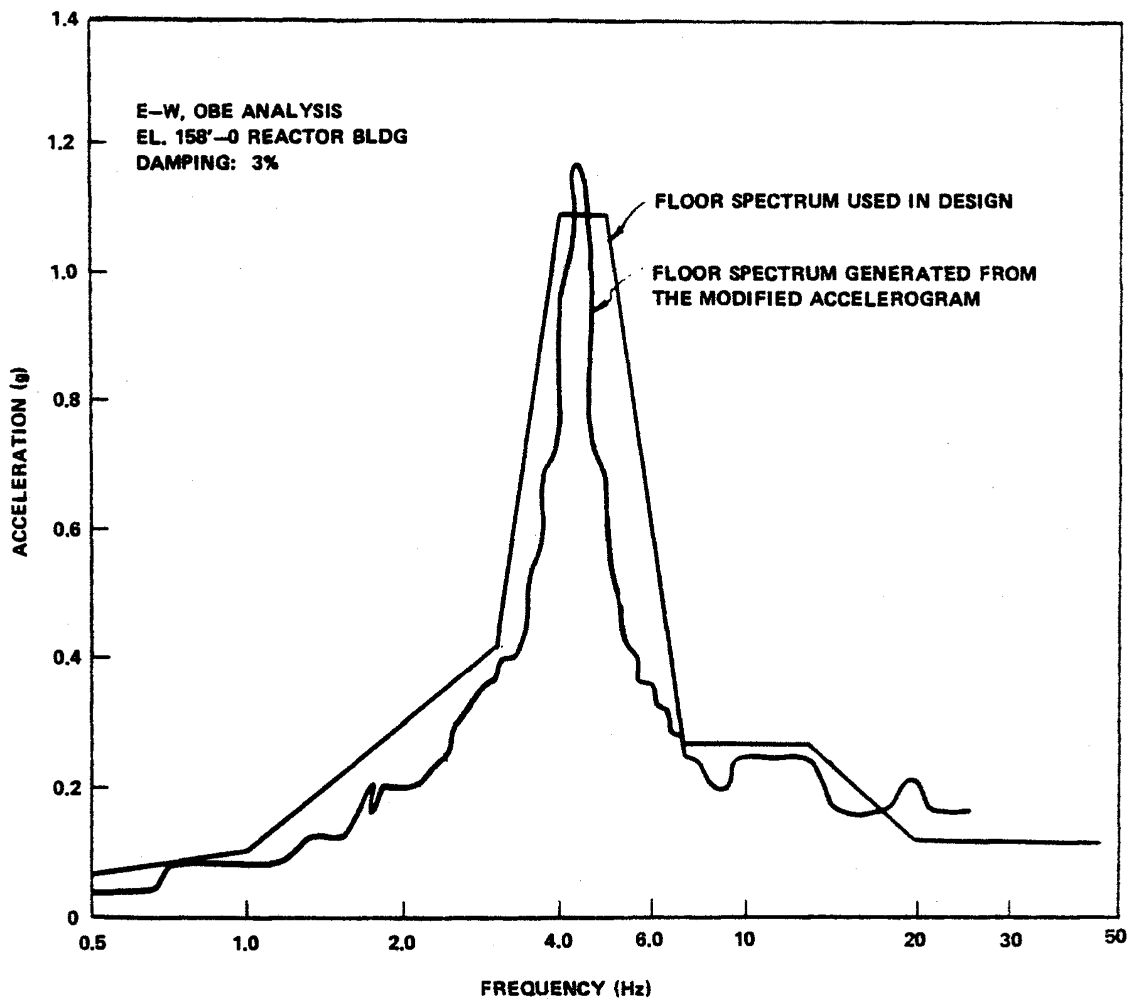
COMPARISON OF THE FLOOR RESPONSE SPECTRA AT REACTOR BUILDING
el 87 ft 0 in.

FIGURE 12.6-5



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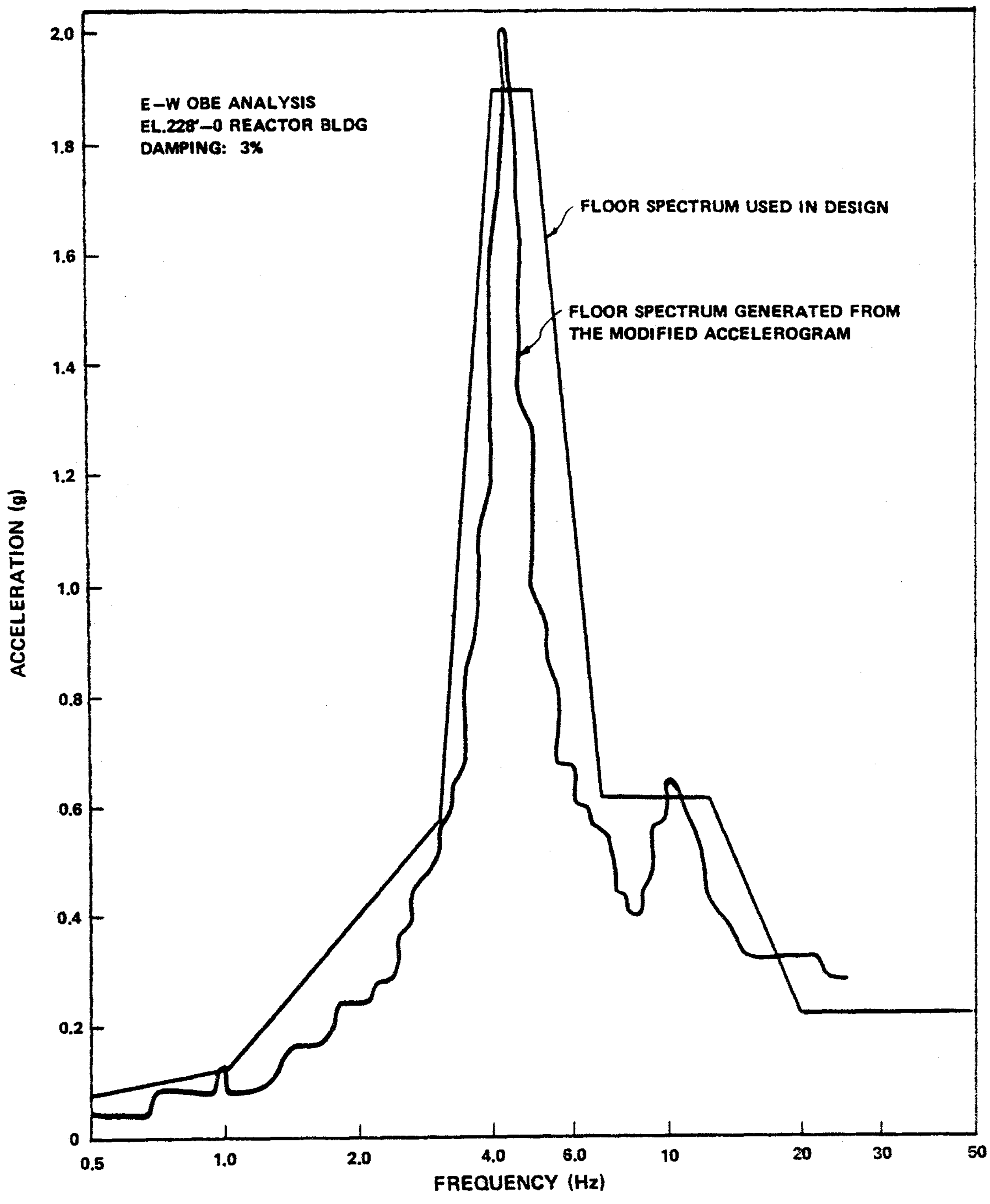
SOUTHERN COMPANY *Energy to Serve Your World®* SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	COMPARISON OF THE FLOOR RESPONSE SPECTRA AT REACTOR BUILDING el 158 ft 0 in.
	FIGURE 12.6-6



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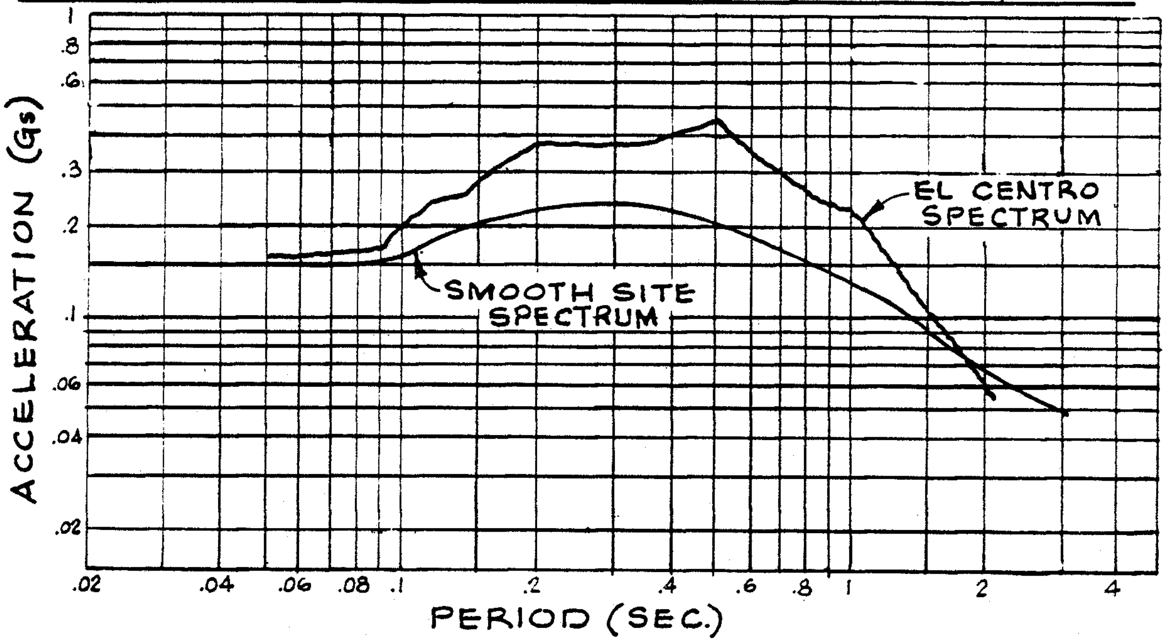
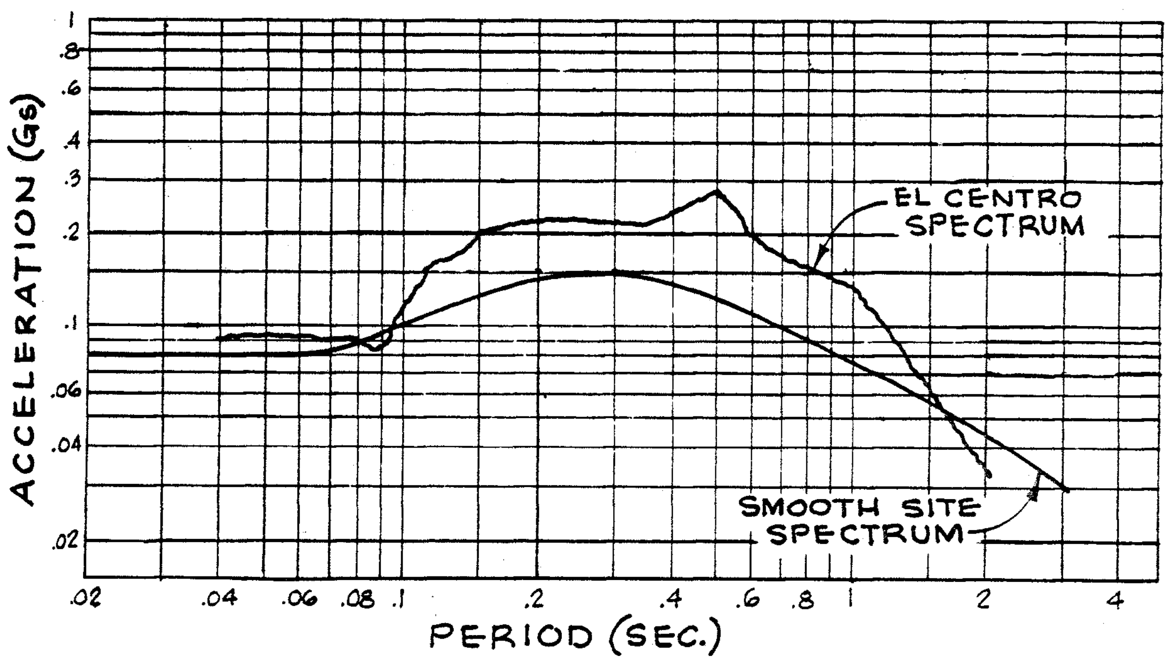
COMPARISON OF THE FLOOR RESPONSE SPECTRA AT REACTOR BUILDING el 228 ft 0 in.

FIGURE 12.6-7

5% CRITICAL DAMPING - DESIGN BASIS EARTHQUAKE



3% CRITICAL DAMPING - OPERATING BASIS EARTHQUAKE



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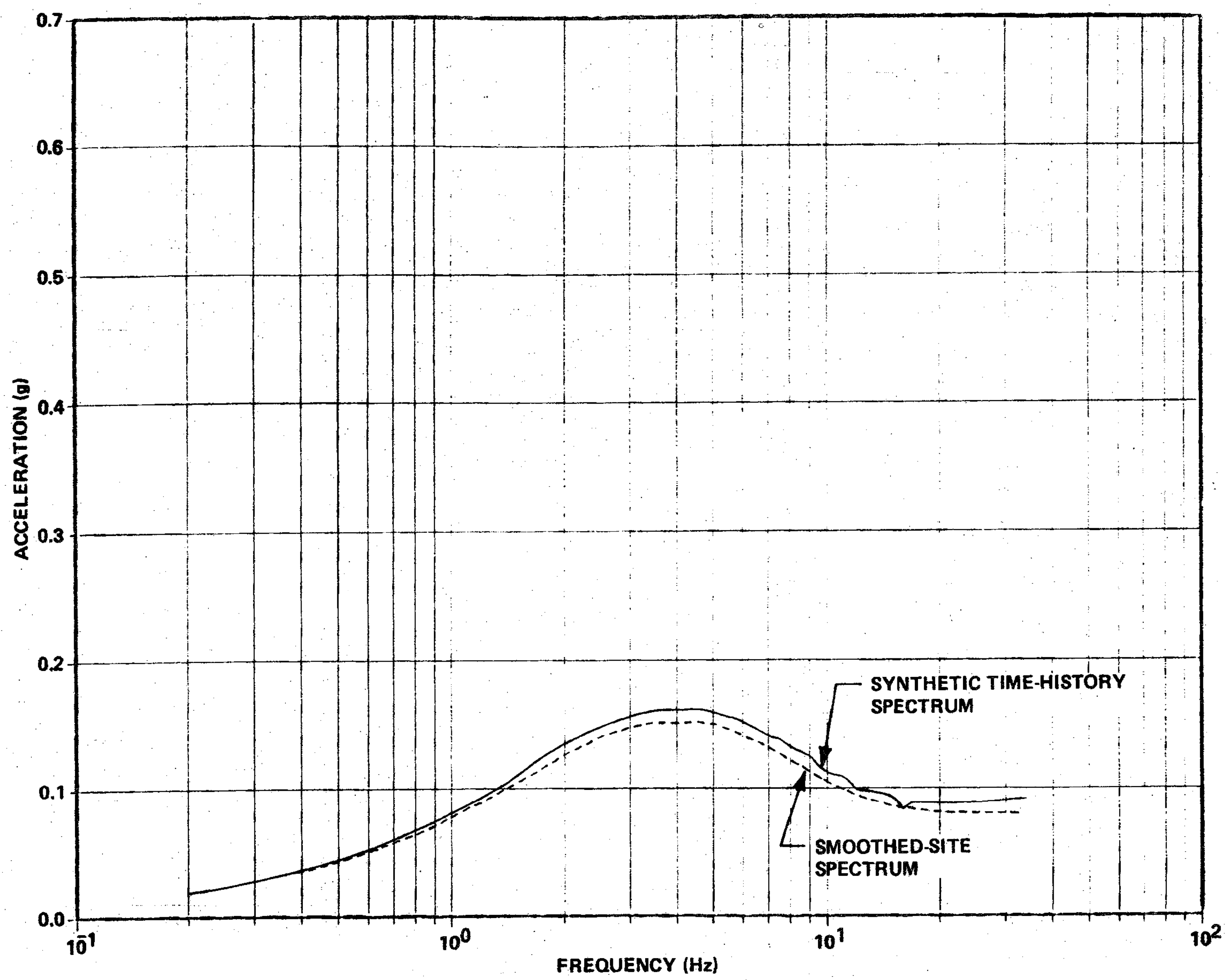
COMPARISON OF TIME-HISTORY RESPONSE SPECTRUM WITH SMOOTHED SITE RESPONSE SPECTRUM

FIGURE 12.6-8



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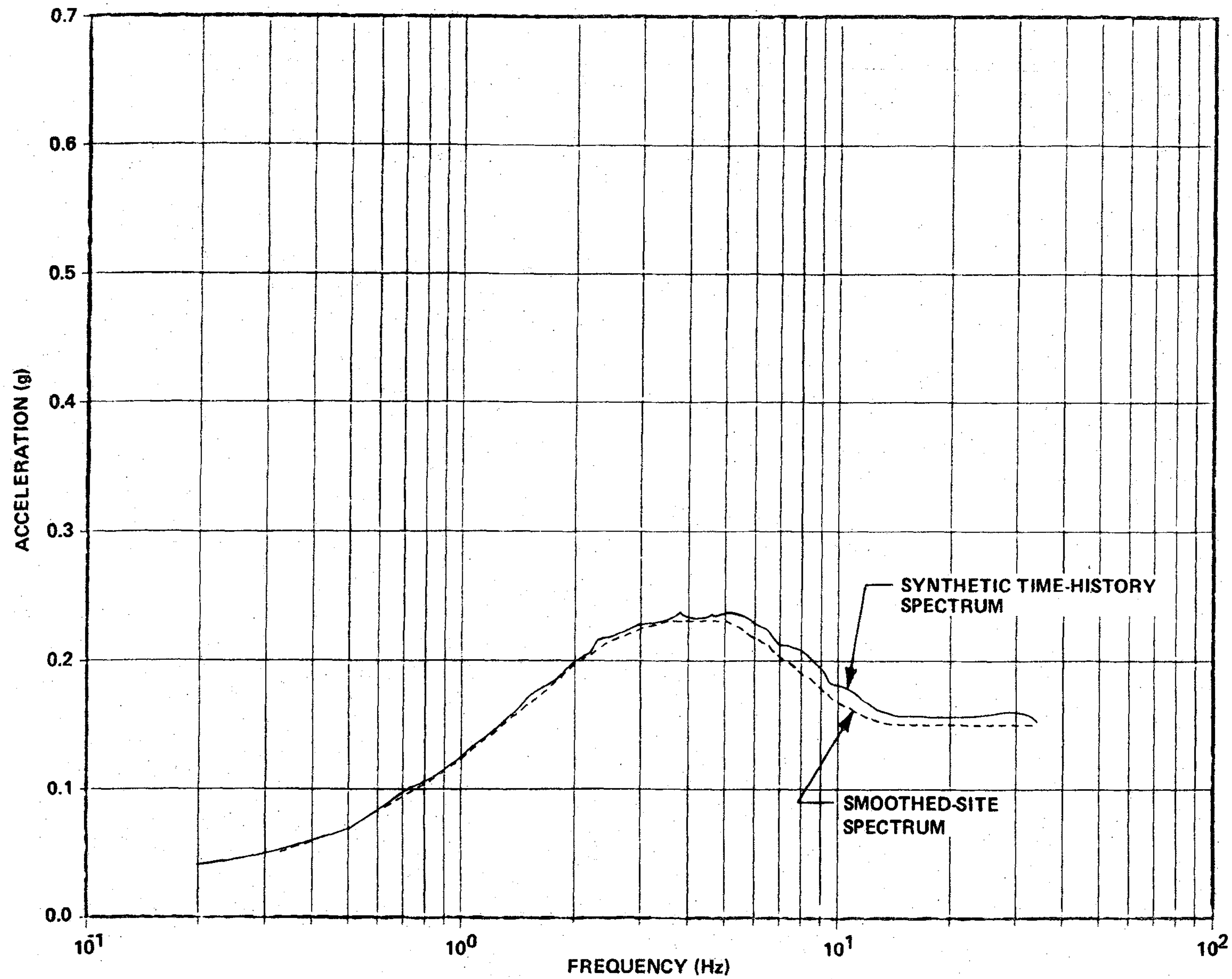
COMPARISON OF OBE SYNTHETIC TIME-HISTORY RESPONSE SPECTRUM WITH SMOOTHED-SITE RESPONSE SPECTRUM AT 3% CRITICAL DAMPING

FIGURE 12.6-9



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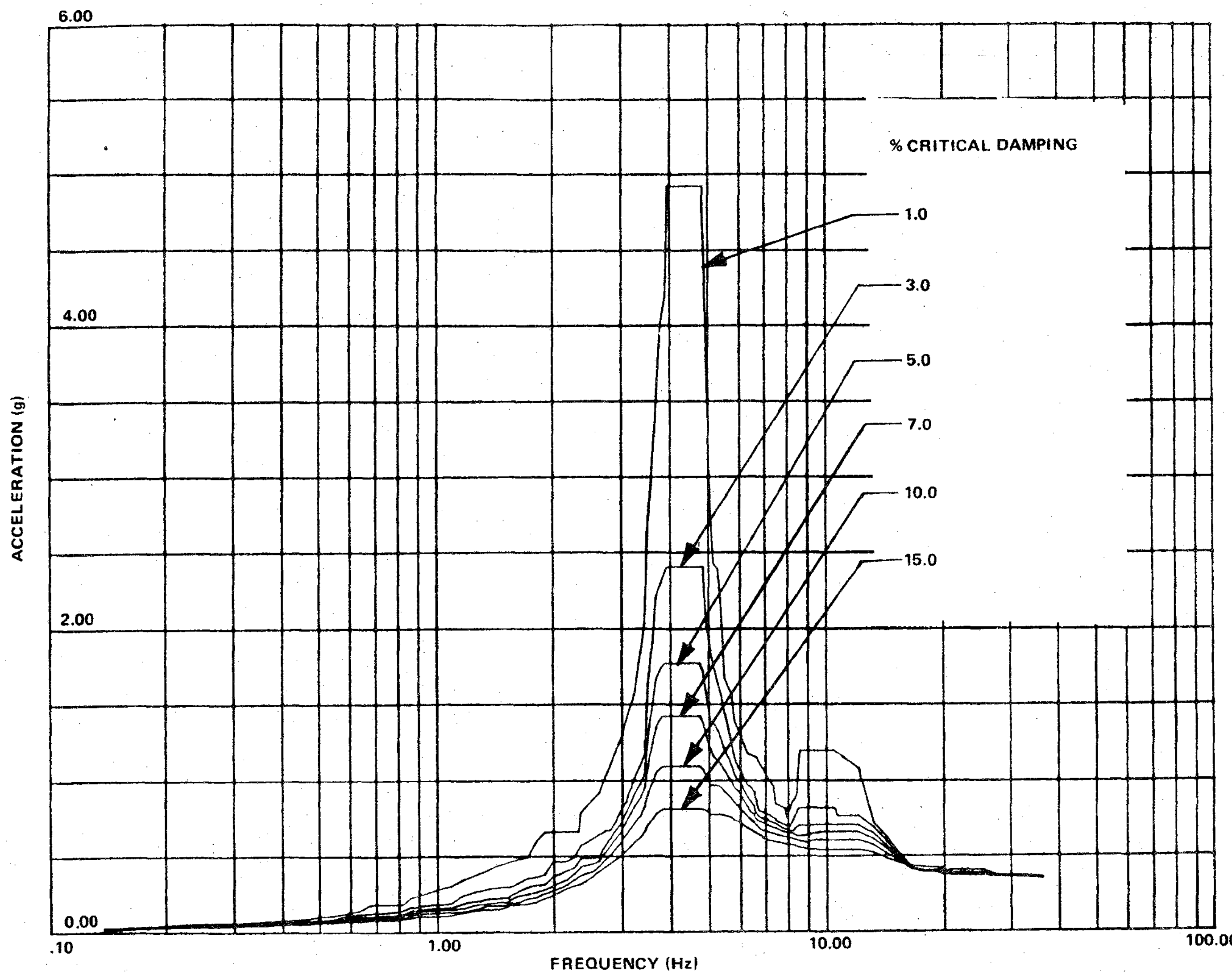
COMPARISON OF DBE SYNTHETIC TIME-HISTORY RESPONSE SPECTRUM WITH SMOOTHED-SITE RESPONSE SPECTRUM AT 5% CRITICAL DAMPING

FIGURE 12.6-10



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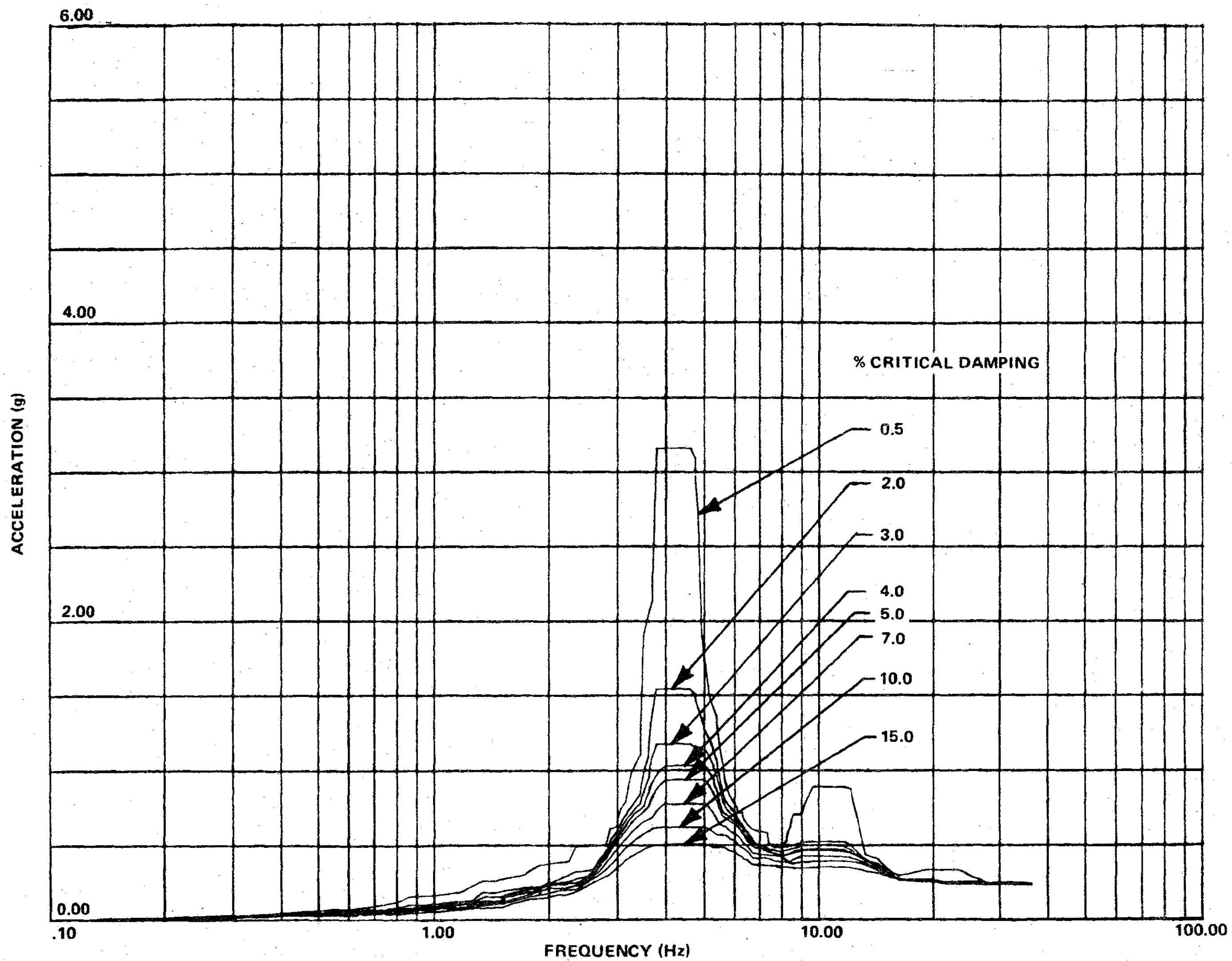
REACTOR BUILDING 1984 RESPONSE SPECTRA DBE (N-S) FOR FLOOR AT el 228 ft

FIGURE 12.6-11



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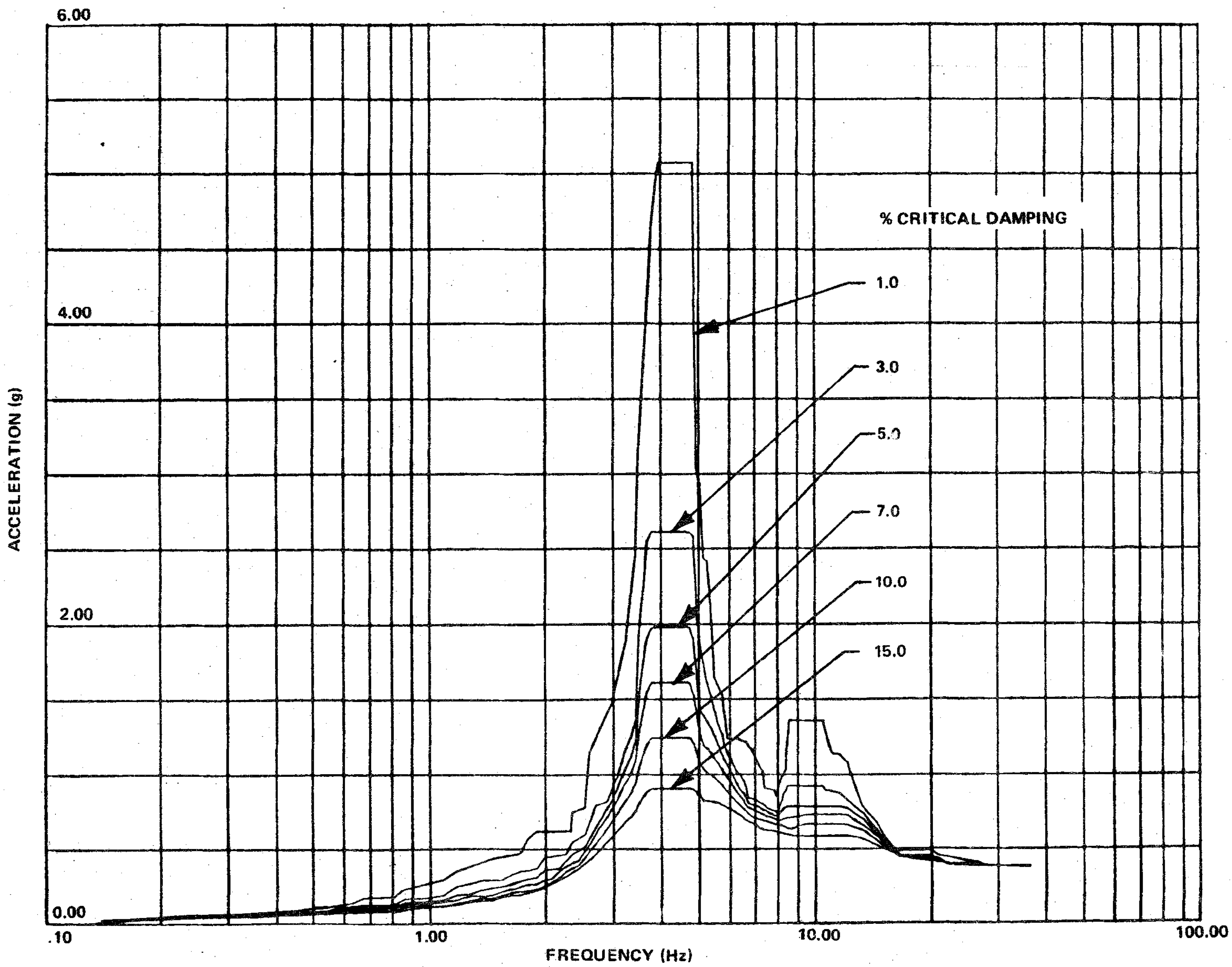
REACTOR BUILDING 1984 RESPONSE SPECTRA OBE (N-S) FOR FLOOR AT el 228 ft

FIGURE 12.6-12



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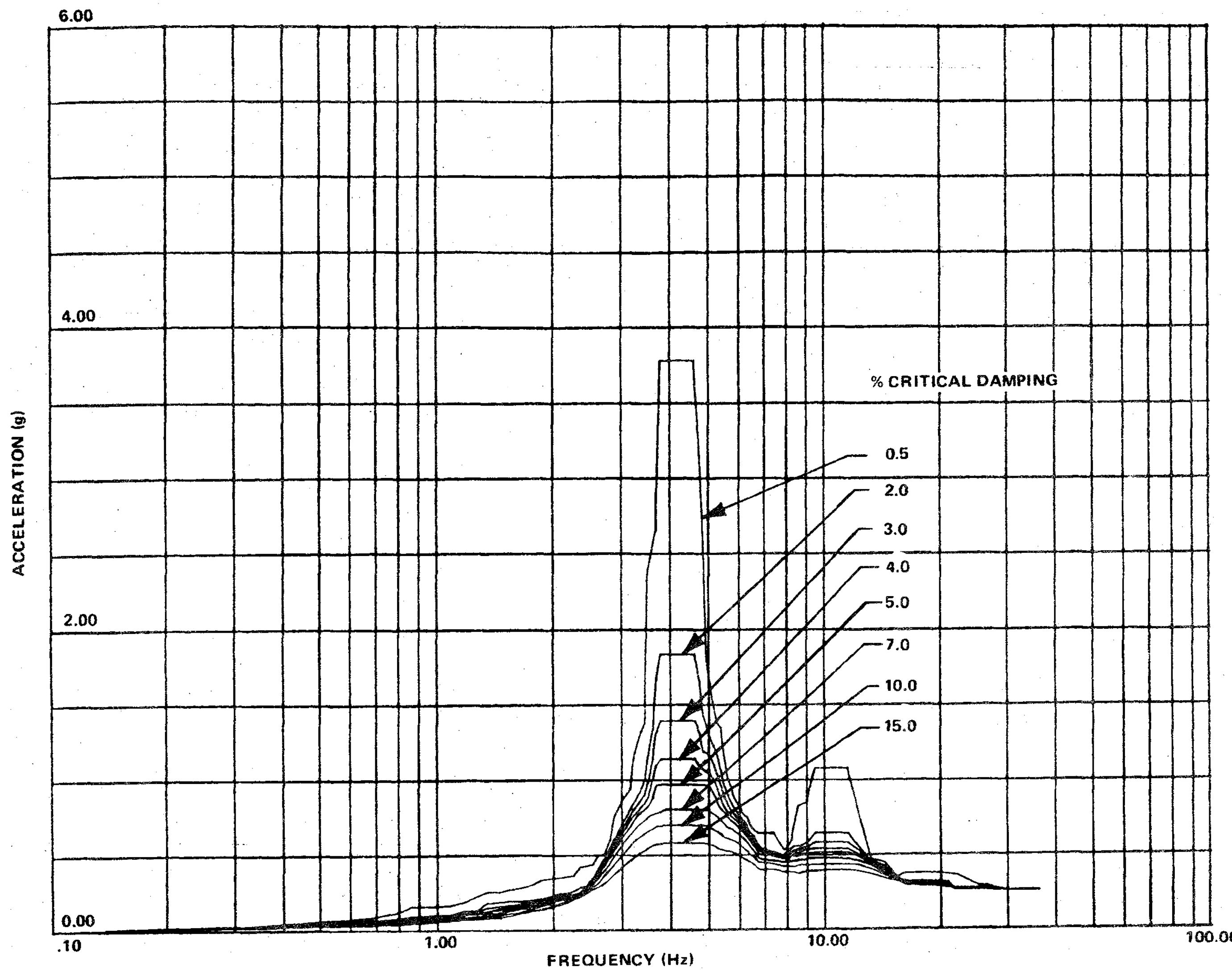
REACTOR BUILDING 1984 RESPONSE SPECTRA DBE (E-W)
FOR FLOOR AT el 228 ft

FIGURE 12.6-13



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REACTOR BUILDING 1984 RESPONSE SPECTRA OBE (E-W)
FOR FLOOR AT el 228 ft

FIGURE 12.6-14

12.7 <u>SHIELDING AND RADIATION PROTECTION</u>

12.7.1 DESIGN BASIS

Refer to HNP-2-FSAR paragraph 12.3.2.1.

12.7.1.1 <u>Radiation Exposure of Materials and Components</u>

Materials and components are selected with radiation resistance as a prime factor. Where vital components have only nominal radiation resistance, shielding is provided to reduce the integrated doses to tolerable values. Additional exposure due to a design basis accident (DBA) is considered in the selection of material or shielding of components which must function during or after such an accident.

The use of certain materials is restricted:

Material	Exclusion
Teflon	In any neutron flux field
Stellite	Minimal quantities in neutron flux field
Halogens	Generally excluded
Mercury	Excluded from primary containment and areas where single boundary failure will permit introduction into primary system

Radiation exposure is factored into the equipment qualification program as described in section 7.16.

12.7.2 RADIATION AREAS AND ACCESS CONTROL

Refer to HNP-2-FSAR paragraph 12.3.1.3.

12.7.3 GENERAL SHIELDING DESCRIPTION

Refer to HNP-2-FSAR paragraph 12.3.2.2.1.

12.7.3.1 <u>Main Control Room</u>

For the DBA, the plant main control room (MCR) was designed using the guidelines of 10 CFR 50, Appendix A, Criterion 19. The DBAs define the protection required for the MCR. Since the MCR is a common facility, the accident conditions and their resultant effects on control room habitability are described in HNP-2-FSAR section 15.4. The shielding design was based on a whole-body integrated dose of less than 0.5 rem in any 8-h period from any direct radiation due to any possible airborne radioactivity external to the control room following an accident. The MCR shielding material and thicknesses are outlined in HNP-2-FSAR paragraph 12.3.2.2.8.

12.7.3.2 Reactor Building

Refer to HNP-2-FSAR paragraph 12.3.2.2.2.

12.7.3.3 Turbine Building

Refer to HNP-2-FSAR paragraph 12.3.2.2.3.

12.7.3.4 Radwaste Building

Refer to HNP-2-FSAR paragraph 12.3.2.2.7.

12.7.3.5 Service Building

Refer to HNP-2-FSAR paragraph 12.3.2.2.9.

12.7.3.6 Main Stack

Refer to HNP-2-FSAR paragraph 12.3.2.2.5.

12.7.3.7 General Plant Yard Areas

Refer to HNP-2-FSAR paragraph 12.3.2.2.10.

12.7.3.8 Skyshine

A comprehensive study, based on a Monte Carlo-type calculation, was undertaken to determine the SKYSHINE dose from N-16 gamma radiation in the turbine buildings for HNP-1 and HNP-2. The dose to a fisherman at the riverbank near the intake structure was calculated to be ~ 3.4 mrem/year (2.1 mrem/year from HNP-1 and 1.3 mrem/year from HNP-2). The calculation was made assuming an 80% plant factor and an occupancy factor of 208 h/year for the fisherman. Surveys of the radiation levels onsite and offsite, at the maximum hydrogen injection rate, have confirmed that the expected annual exposure is within the limit of 10 CFR 20.1301.

12.7.3.9 Technical Support Center

The DBAs define the protection required for the TSC. Since the TSC is a common facility, the accident conditions and their resultant effects on TSC habitability are described in HNP-2-FSAR chapter 15. The shielding design and basis are outlined in HNP-2-FSAR paragraph 12.3.2.2.11.

12.7.3.10 Independent Spent Fuel Storage Installation (ISFSI)

Refer to HNP-2-FSAR paragraph 12.3.2.2.12.

12.7.3.11 Low-Level Radioactive Waste (LLRW) Storage Facility

Refer to HNP-2-FSAR paragraph 12.3.2.2.13.

12.7.4 INSPECTION AND PERFORMANCE ANALYSIS

The normal construction quality control program assures there are no major defects in the shielding. After startup, the adequacy of the shielding and the efficiency of the access control are checked by radiation and contamination surveys performed at various reactor power levels. For maintenance work in restricted areas, general surveys are conducted prior to personnel entering these areas.

12.8 SEISMIC EVALUATION OF RADWASTE FACILITIES BUILDINGS

See HNP-2-FSAR subsection 3.8.7.

12.9 RESPONSES TO UNITED STATES NUCLEAR REGULATORY COMMISSION (USNRC) INSPECTION AND ENFORCEMENT (IE) BULLETINS

This section provides a summary of the responses to the following two US NRC IE Bulletins.

- USNRC IE Bulletin 80-11, "Masonry Wall Design."
- USNRC IE Bulletin 79-02, "Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts."

12.9.1 SUMMARY OF THE RESPONSES TO USNRC IE BULLETIN 80-11, "MASONRY WALL DESIGN"

See HNP-2-FSAR subsection 3.8.6.

12.9.2 SUMMARY OF THE RESPONSES FOR IE BULLETIN 79-02, "PIPE SUPPORT BASE PLATE DESIGNS USING CONCRETE EXPANSION ANCHOR BOLTS"

12.9.2.1 Introduction

For Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1), the pipe support base plate design has been reevaluated in accordance with the requirements of IE Bulletin 79-02 (March 8, 1979), Revision No. 1 (June 21, 1979), Supplement No. 1 to Revision 1 (August 20, 1979), and Revision 2 (November 8, 1979).

12.9.2.2 Concrete Expansion Anchor Testing and Replacement Program

In the interest of economics and safety, based on the time, effort and results of those efforts required for the anchor testing and replacement program on HNP-2, Georgia Power Company (GPC) management decided to replace all self-drilling anchors required to take tension loadings with wedge-type anchors.

A description of the above action follows in the form of responses to specific attributes of IE Bulletin 79-02.

12.9.2.2.1 Base Plate Flexibility and Design Criteria

Flexibility of the replacement plates and the originally installed plates which remained was taken into account in determining anchor bolt loadings. This was done through the utilization of an empirical-analytic technique (developed by Bechtel) which takes into account design parameters such as flexibility of the base plates and concrete anchors stiffness (based on actual load-displacement curves furnished by the anchor bolt manufacturer). This method has been verified with appropriate finite element solutions.

A computer program for the empirical-analytic technique has been implemented for determining the bolt loads for routine applications. The program requires plate dimensions, attachment size, number of bolts, bolt size, bolt spacing, bolt stiffness, the applied forces, and the allowable bolt shear and tension loads as inputs. The allowable loads for a given bolt are determined based on the concrete edge distance, bolt spacing, embedment length, shear cone overlapping, anchor ultimate capacity, and a design safety factor. HNP-2-FSAR supplement 3.8D provides criteria for determining expansion anchor bolt loads in pipe support base plates.

The program computes the bolt forces and calculates shear-tension interaction value based on the allowable loads. The following interaction equation is considered adequate:

$$\left[\frac{\text{Design tension}}{\text{Allowable tension}}\right]^2 + \left[\frac{\text{Design shear}}{\text{Allowable shear}}\right]^2 \leq 1.00$$

An interaction value greater than one indicates bolt inadequacy (safety factor less than required).

For special cases where the design of the support does not lend itself to this method, standard engineering analytical techniques with conservative assumptions were employed.

12.9.2.2.2 Safety Factors for Expansion Anchors

A minimum safety factor of 4.0 between the bolt design load and the bolt ultimate capacity was verified to exist for wedge-type anchors, and a minimum safety factor of 5.0 was maintained for the self-drilling shell-type anchors. It should be noted that, in general, support devices were modified as necessary to eliminate reliance on shell-type employed in tensile loaded configurations.

However, for factored loadings (which include accident/extreme environmental loads), a safety factor of 3.0 could have been used commensurate with the provisions of Section B.7.2 of the Proposed Addition to Code Requirements for Nuclear Safety-Related Concrete Structures (ACI 349-76), August 1978. Also based on the Hatch program of 100% verification of acceptable anchor bolts following rework, it would have been justifiable to reduce the safety factor to 2.0.

The bulletin factors of safety were met including design basis earthquake (safe shutdown earthquake) loadings in the design bolt load.

12.9.2.2.3 Cyclic Loads

In the original design of the piping system, Bechtel considered dead-weight, thermal, seismic, and dynamic operating loads where applicable, in the generation of the static equivalent pipe support design loads.

The safety factors used for concrete expansion anchors were not increased for those portions of the support load which are cyclic in nature. The use of the same factor for cyclic and static loads is based on the fast-flux test facility tests.[a] The test results indicate:

A. The expansion anchors successfully withstood 2 million cycles of long-term fatigue loading at a maximum intensity of 0.20 of the static ultimate capacity. When the maximum load intensity was steadily increased beyond the aforementioned value and cycled for 2000 times at each load step, the observed failure load was about the same as the static ultimate capacity.

B. The dynamic load capacity of the expansion anchors, under simulated seismic loading, was about the same as their corresponding static ultimate capacities.

C. Preload is not a requirement for the anchor bolts to function in a dynamic environment.

12.9.2.2.4 Expansion Anchor Testing Program

Due to insufficient documentation of the existing installations and, as a result of the test data obtained from HNP-2 and the efforts required to obtain and evaluate this data to determine the need for corrective action, GPC management decided to replace shell-type anchors used in pipe supports in the systems described below with wedge-type anchors.

The following system piping was included in the surveillance and replacement program:

A. All large bore (> 2 1/2-in. nominal diameter) piping systems required to function and/or support the function of systems to mitigate the consequences of the design basis accidents discussed in HNP-2-FSAR, chapter 15, Safety Analysis, were included in this program.

B. Computer analyzed piping systems ≤ 2 1/2-in. nominal diameter, in safety-related systems were also included.

---

a. Drilled-In Expansion Bolts Under Static and Alternating Loads, Report No. BR-5853-C-4, Bechtel Power Corporation, January 1975.

C. If < 2 1/2-in. diameter pipe was supported using an engineered field procedure, i.e., the cookbook method, the support systems were not included in this program, unless that portion of pipe was originally analyzed with the main piping system. In that case, < 2 1/2-in. diameter pipe supports were inspected from the main pipe to the first anchor on the smaller line.

The specific systems or portions of HNP-1 systems which had 100% expansion anchor testing or replacement are as follows:

- Primary steam drainage (computer analyzed portion).
- SLCS (pump suction and discharge piping up to containment penetration, Seismic I portion).
- HPCI system (containment isolation portion).
- RCIC system (containment isolation portion).
- H_2 and O_2 analyzer system (containment isolation portion).
- Drywell pneumatic system (containment isolation portion).
- Diesel oil system (oil piping from day tank to diesel, starting air, and cylinder jacket cooling water).
- N_2 inerting system (containment isolation portion).

Since 100% testing of wedge-type expansion anchors and replacement of self-drilling-type anchors with wedge-type was performed on the above listed systems, it is felt that the supports employing expansion anchors subject to higher concern with regard to system operability have been covered by the program. (Note: Small pipe inside the containment relies on welded supports for operability.)

Other supports outside the containment supported by cookbook methods have conservatisms inherent to this method of pipe supporting. Since no major items which would affect system operability were identified during the testing or replacement of those small pipe supports which were covered by this program, plant safety is not considered to be in jeopardy.

D. All the anchors not required to take tension loading through their support systems were not included in this program.

E. Containment penetrations smaller than 2 1/2-in. piping installed with motor- or air-operated isolation valves (a heavy concentration of weight) and supported using standard cookbook methods were included in this program up to the first anchor beyond the second isolation valve.

Piping and instrument diagrams, isometric drawings for the large bore and small bore piping and, if necessary, physical piping drawings, were yellow lined to identify the piping and systems which were to be subjected to the anchor replacement program. The program included the following systems:

- B21 Nuclear boiler system.
- C11 Control rod drive system (scram discharge volume).
- C41 Standby liquid control system (SLCS) (pump suction and discharge pipe up to containment penetration, Seismic I portion).
- E11 Residual heat removal system.
- E11 Residual heat removal service water (RHRSW) system.
- E21 Core spray (CS) system.
- E41 High-pressure coolant injection (HPCI).
- E51 Reactor core isolation cooling (RCIC).
- G11 Radwaste system (from containment penetration to first anchor beyond second isolation valve).
- G31 Reactor water cleanup (RWC) system (containment isolation portion and connection to feedwater from F039).
- G41 Fuel pool cooling system (Seismic I piping).
- N11 Main steam isolation valves (MSIVs) to first anchor beyond turbine stop valves and branches 2 1/2 in. and larger to first isolation valve).
- P11 Condensate supply system (Seismic I portion only).
- P33 H_2 and O_2 analyzer system (containment isolation portion only).
- P41 Service water system (reactor building, diesel building, and intake structure).
- P42 Reactor building closed cooling water system (containment isolation portion only).
- P52 Instrument air system.
- P70 Drywell pneumatic system (containment isolation portion only).

- R43 Diesel oil system (oil piping from daytank to diesel, starting air, and cylinder jacket cooling water).

- T46 Standby gas treatment system.

- T48 Drywell to torus ΔP (containment isolation portion only).
  Containment purge and inerting system N_2 inerting system (containment isolation portion only).

- Z41 Control room environmental system.

- — Miscellaneous supports within the primary containment which employ concrete expansion anchors.

The initial step in the Unit 1 effort was to identify the supports which employed expansion anchor bolts by means of a system walk-down surveillance program in accordance with procedure HNP-1-11004, HNP-1 Hanger Surveillance.

Identification of supports was made by comparing the installed supports to the stress analysis locations and as-designed support detail sketches. When the attachment to the building structures was determined to employ expansion anchor bolts, a dimensional check of the support was made to ensure that the design group had pertinent data with which to perform calculations required for replacement of shell-type anchors and, in some cases, check existing wedge-type or WEJ-IT anchors.

Anchor replacement and testing was conducted in accordance with procedure HNP-1-11005, HNP-1 Hanger Rework Program. In many cases, due to accessibility and economy, base plates were replaced with larger and/or thicker plates. The methods described were employed to determine the design loads for the replacement anchors.

Wedge-type and WEJ-IT anchors which were not replaced were subjected to verification of proper thread engagement, anchor diameter, length, and bolt preload. Verification of proper installation of bolts was made using torque values based on manufacturer's data. This data was forwarded to design engineers for evaluation.

During the course of the program, various discrepancies were identified such as missing supports and portions of systems which were not seismically qualified. These items are identified in table 12.9-1.

Also due to the accessibility problems associated with the RWC system from the containment to the RWC pump suction, the self-drilling anchors were not replaced with wedge type.

Upon review of the support system for this section of piping, it was noticed that the self-drilling anchors used had quite large safety factors. The reason for this was because more of the supports had been designed and installed prior to a reanalysis of the piping which resulted in lower support loads.

Since the surveillance done on this piping did not reveal any indications of support inadequacy, and due to the large safety margins which exist (table 12.9-2), it was determined that the integrity of the piping system was not in jeopardy, and therefore public safety was not in question.

12.9.2.2.5 Expansion Anchor Bolts in Concrete Block Walls

A walkdown inspection of HNP-1 and HNP-2 was performed to determine the extent that expansion anchor bolts were used in concrete block walls to attach piping supports within the scope of IE Bulletin 79-02 as defined in paragraph 12.9.2.2.4.

No supports were identified for the safety-related systems which were inspected.

12.9.2.2.6 Structural Shapes Attached Directly to Walls

The scope of the testing and replacement programs for HNP-1 included all supports relying on expansion anchor bolts for support of the piping covered in the program, whether utilizing base plates or structural shapes attached directly to walls. It should be noted that structural shapes were generally not attached directly to the building walls. Only a few cases were identified during the program, and these were given the same consideration as the other supports.

12.9.2.2.7 Inaccessible Anchor Bolt Testing

Inaccessible expansion anchor bolts are discussed in paragraph 12.9.2.2.4.

12.9.2.2.8 Inspection Documentation

Inspection documentation for the HNP-1 and HNP-2 testing and replacement programs are available onsite.

TABLE 12.9-1

DISCREPANCIES IN HNP-1 HANGER REWORK PROGRAM

Description of Deviation	Resolution
Radwaste system - Two 3-in. lines penetrating containment were not supported seismically.	Piping was analyzed and supported to meet seismic criteria.
CS/radwaste system - A 2 1/2-in. line between a reactor building floor drain sump and CS test line was not supported seismically.	Piping was analyzed and supported to meet seismic criteria.
RCIC system - Two lateral supports on the RCIC pump suction piping were not installed.	Piping was analyzed without the supports with results that verified that piping integrity would be maintained without the supports. The supports were installed to conform to original analysis.
Flued-head penetration anchors - Seven penetration anchors did not have the originally intended safety margins due to nonconservative simplified design assumptions used in the original design.	The penetration anchors were analyzed by present-day techniques which verified that although the originally intended safety margins were not existing, the overall safety factor was > 1.0. The anchors were modified to restore the originally intended safety factors.

TABLE 12.9-2

RWC PUMP SUCTION SUPPORTS EMPLOYING SELF-DRILLING ANCHORS

Support No.	%[a]	
2	5.1	Conservative (only 4 of 8 bolts assumed to act in tension)
4	3.15	Conservative (only 4 of 6 bolts assumed to act in tension)
7	2.0	
8	2.0	
10	0.6	
11	2.0	
13	0.6	
15	0.6	
16	0.6	
16A	1.2	
18	0.6	
20	0.6	
21	0.6	
21A	1.2	
99	-	Support not required to resist tension
199	-	Negligible tension load (17 lb)

a. The values indicated in this column express bolt design load as a percentage of the manufacturer's ultimate bolt capacity.

13.0 CONDUCT OF OPERATIONS

13.1 (Deleted)

13.2 ORGANIZATION AND RESPONSIBILITY

See HNP-2-FSAR section 13.1.

13.3 TRAINING ORGANIZATION AND RESPONSIBILITY

See HNP-2-FSAR section 13.2.

13.4 PREOPERATIONAL TEST PROGRAM

13.4.1 OBJECTIVES

The preoperational test program is basically a systems test program which begins after significant construction is complete and extends through initial fuel loading. Preoperational testing will prove the general criteria established in the Final Safety Analysis Report and will:

- *Confirm that construction is complete to the extent that equipment and systems can be put into use during construction.*

- *Adjust and calibrate the equipment to the extent possible in the "cold" plant.*

- *Demonstrate functional performance of safety-related systems and compliance with license requirements to the extent necessary to proceed into initial fuel loading and the startup test program.*

Key systems are sequenced for completion and testing early enough to provide auxiliary services for testing and operation of other systems or for construction activities, e.g., the use of the makeup system for cleaning. This results in an early requirement for electrical systems, demineralized water makeup, and cooling water systems.

Georgia Power Company's (GPC) production department personnel will operate the plant and equipment during preoperational testing as an important phase in the training of the nuclear system operators. Experience and understanding of plant systems and components is gained with a maximum accessibility to the system personnel. Minimal restrictions are imposed on either the operators or the testing. This gives maximum opportunity to evaluate and train individual operators and to troubleshoot plant systems. In addition, plant equipment and systems are operated for a sufficient period of time to discover and correct any design, manufacturing, or installation errors, and to adjust and calibrate the equipment.

Subsection 13.4.3 discusses the preoperational test program sequence and procedure considerations. Subsections 13.4.4 through 13.4.11 are included to indicate system test prerequisites, to define system test objectives, to indicate in summary form the scope of preoperational testing, and to highlight examples of minimal restrictions needed to assure subsequent safety. Preoperational tests are to be performed using detailed written procedures issued prior to the test.

13.4.1.1 Administrative Procedures

The administrative procedures for preoperational testing require a preoperational test specification and a preoperational test procedure to be written for every preoperational test.

A preliminary preoperational test specification will be written by the respective design organization responsible for design of the system, either Southern Company Services (SCS), General Electric (GE), or Bechtel. The specification will include prerequisites, objectives of the test, acceptance criteria, precautions, special test equipment required, and a list of references. Copies of this preliminary *specification will be transmitted to the plant superintendent-production department who along with the preoperational test coordinator (technical supervisor) will submit their comments to the respective design organization.*

The design organization will then prepare a final preoperational test specification and copies of it will be transmitted to the plant superintendent. The preoperational test coordinator will distribute copies of the specification to the appropriate test supervisor designated by the plant superintendent responsible for writing the preoperational test procedure. The test procedure will include a detailed step-by-step test procedure for compliance with the test specification and instructions for restoring nonstandard arrangements to their standard status following completion of the test.

The test procedure will be reviewed by the plant review board and recommendations for approval made to the plant superintendent. The approval by signature under procedure review will be required from the following: plant superintendent, designated GE onsite representative, designated Bechtel onsite representative, and designated SCS onsite representative, respectively. Before signing, the onsite representatives will ensure that each procedure complies with its corresponding specification. The Bechtel representative will review and approve the procedure for both Bechtel and SCS; he has direct contact with the respective design groups to resolve any problems. Following the last signature the procedure will be returned to the test coordinator

If there are no comments from any of the reviewing groups, the test coordinator will resubmit the procedure to the review chain for the release for execution signature (first SCS, Bechtel, GE, then the plant superintendent). If the procedure is unacceptable, the onsite representatives will recommend necessary changes and, after incorporation of the changes by the person originally responsible for writing the procedure, it will be returned through the approval chain obtaining the release for execution approval signatures.

The preoperational test coordinator (technical supervisor) will issue the properly signed procedure to the responsible test supervisor. The test supervisor will direct the running of the test, and if complications should arise or the acceptance criteria cannot be met, the technical supervisor, plant superintendent, and onsite representatives will coordinate with the respective design organization any system modifications or procedure changes necessary to ensure the system meets the acceptance criteria.

The successfully completed preoperational test will be reviewed by the technical supervisor and then forwarded to the plant review board, plant superintendent, and the onsite Bechtel and GE representative, all for review and approval.

The signed procedure and all accompanying documents will be placed in the plant quality assurance files.

13.4.2 CONSTRUCTION ASSURANCE TESTING

Many testing requirements actually precede the preoperational testing program. These are categorized as construction assurance tests and are performed by subcontractors or GPC production personnel under the surveillance of GPC construction department personnel. The tests resemble preoperational tests in that they are defined by formalized procedures and data sheets and require formal reporting and acceptance.

13.4.2.1 Construction Assurance Tests

Construction assurance testing includes but is not limited to:

- *Containment leak rate testing.*
- *System hydrostatic tests.*
- *Chemical cleaning and flushing.*
- *Wiring continuity checks.*
- *Megger and high-potential tests.*
- *Electrical system tests including energizing.*
- *Initial adjustment and rotational checks.*
- *Checking control and interlock functions of instruments, relays, and control devices.*
- *Calibrating instruments and checking or setting initial trip setpoints.*
- *Pneumatic testing of instrument and service air system and cleaning of lines.*
- *Equipment adjustments such as alignment, greasing, and tightening of bolts.*
- *Checking and adjusting relief and safety valves.*
- *Complete tests of motor-operated valves including adjusting limit switches, checking all interlocks and controls, measuring motor current and operating speed, and checking leaktightness of stem packings and valve seats during hydrotests.*
- *Complete tests of air-operated valves including checking all interlocks and controls, adjusting limit switches, measuring operating speed, checking leaktightness of stem packings and valve seats during hydrotest, checking leaktightness of pneumatic operators, and checking for proper operation of controllers, pilot solenoids, etc.*
- *Nondestructive testing of field welds.*

- *Verification of correct installation of components.*

13.4.2.2 Electrical System Tests

The dc system will be placed into service as required to provide auxiliary power to the plant in a safe manner. Other portions of the dc system may be completed as required.

Equipment in the reactor protection system (RPS) and vital bus power supply will require functional preoperational testing to verify adequacy of design and installation. Other testing performed by the GPC production department personnel will be in the nature of construction assurance tests on wiring and individual components such as the following:

- *Continuity and phasing checks.*
- *Megger test on required control wiring.*
- *Relay tests and adjustments.*
- *Checking for proper operation of transformer cooling and instrumentation.*
- *Checking circuit breaker operation and controls.*
- *High-potential tests, where required.*
- *Checking the calibration of meters.*
- *Checking for proper operation of all controls.*

13.4.3 PREOPERATIONAL TEST PROGRAM SEQUENCE AND PROCEDURE CONSIDERATIONS

The following key points will be considered in developing the sequence and procedures of the preoperational test program:

A. *Supporting systems are sequences for early checkouts and are placed in routine operation to provide necessary auxiliary services for other systems. Examples are plant electrical systems, instrument air, makeup water supply, and service water systems.*

B. *Preoperational testing is coordinated with construction to permit fuel loading as early as possible without compromising nuclear safety or impeding construction work. As a result, fuel loading is to be scheduled while construction work is still in progress on unrelated systems and areas.*

C. *Stricter controls of unit operation and maintenance work are required following fuel loading. To minimize possible contamination problems, acceptance testing is to be* *scheduled, to the extent possible, before fuel loading on all components and systems which could consequently be exposed to radioactive contamination except where full system testing cannot be performed until after fuel loading.*

D. Preoperational tests provide an important phase of the plant operators' training program and are scheduled on key systems to permit maximum participation by all operators prior to licensing examinations.

E. Temporary construction power is sometimes required for initial tests at the beginning of the preoperational test program. However, unnecessary use of temporary power and improvised setups is to be avoided because of the possibility of costly errors and inconsistency with the ultimate objective of proving the final installation.

F. Electric jumpers are used to facilitate preoperational testing in some instances, but their use is minimized and controlled by proper identification of such jumpers by tags on the equipment jumpered and by log book records.

G. When the plant is ready for fuel loading, construction workers are not to be permitted in the reactor building and drywell. Strict control is enforced over access to the control room, electrical equipment rooms, reactor building, and the radioactive waste treatment area.

H. Specialized electronic equipment and nuclear instrumentation manufactured by GE is checked and preoperationally tested by GPC production department personnel assisted by GE representatives.

I. Detailed test procedures are specific regarding intent, methods, and operating requirements for completing the test and will include detailed blank data sheets to be completed during the test.

J. In general, tests are performed using permanently installed instrumentation for the required data. Special instrumentation, as specified in the preoperational test procedure, defines the interactions and control procedures necessary to maintain operating continuity, system integrity, and plant safety without compromising test efficiency.

K. Where the unit being tested shares components or systems with the unit which is still under construction or in operation, the detailed preoperational test procedure defines the interactions and control procedures necessary to maintain operating continuity, system integrity, and plant safety without compromising test efficiency.

13.4.4 AUXILIARY SYSTEMS TESTS

13.4.4.1 <u>Fuel-Handling Equipment Test</u>

Equipment covered in this category will be tested with load equivalent to dummy fuel or blade guide assemblies through dry run simulations of the required operations. This test consists of many separate operations using different pieces of equipment. The equipment is tested on the operating floor, in the fuel storage pool, and both over and in the reactor vessel.

13.4.4.1.1 Tests in the Spent-Fuel Storage Pool

A. *Install fuel pool gates and fill pool with water. Pressurize seals if necessary.*

B. *Check fuel preparation machine with simulated dummy fuel assembly. This also checks auxiliary tools such as channel handling tools and channel bolt wrenches.*

C. *Check fixed lights and moveable underwater lights to assure adequate visibility for fuel and blade handling and transfer operations.*

D. *Check underwater vacuum cleaner.*

E. *Operate refueling platform over storage pool. Check all equipment on the refueling platform. Transfer fuel assemblies between storage racks with the grapple. Check all grapple controls and interlocks.*

13.4.4.1.2 Tests Over Reactor Vessel

A. *Set service platform assembly on vessel flange.* [Note: Service Platform is no longer available.]

B. *Raise water level in reactor well and check leaktightness of refueling bellows assembly and drywell to reactor well seal. Lower water level and check ability and rate of fuel pool cooling system to drain these seals or associated low points.*

C. *Verify procedural methods and tools for:*

- *Removal and replacement of steam dryer.*
- *Removal and replacement of shroud head steam separator assembly.*
- *Removal and replacement of control rod blades and fuel support pieces.*
- *Simulate the removal and replacement of incore flux monitor tool strings using a neutron source holder for tool fit.*

All of the preceding tests recognize the shielding requirements of doing the job "hot" and attempt to simulate normal operating conditions.

D. *Transfer simulated dummy fuel assemblies and control blades between the storage pool and the reactor vessel simulating a refueling operation.*

E. *Obtain representative values of the time required to do all operations normally in the critical path of a refueling outage.*

13.4.4.2 Reactor Building Closed Cooling Water (RBCCW) System

The objective of the preoperational tests will be to verify the functional capability, flows, and instrumentation in the cold condition.

13.4.4.3 Plant Service Water System

The objective of the preoperational test will be to verify the functional capacity of the plant service water system to provide cooling water for the RBCCW system and various heat exchangers. The test will verify system flows, instrumentation, and controls in the cold condition.

13.4.4.4 Main Steam Off-Gas, Main Stack, and Reactor Buildings Ventilation Radiation Monitoring Systems

Check and/or calibrate relays, sampling pumps, recorders, trips, interlocks, valve operations, and logic associated with these systems.

13.4.4.5 Equipment Area Cooling System and Main Control Room (MCR) Environmental Control System

Check and/or calibrate relays, temperature sensors, pressure sensors, trips, interlocks, and logic associated with these systems.

13.4.4.6 Electric System Test, Normal Auxiliaries

Check and/or calibrate all protective devices, interlocks, follow-up schemes, and other electrical components. Verify insulation and/or circuit continuity and functional operation.

13.4.4.7 Instrument and Service Air System

Check and/or calibrate all instrumentation, interlocks, and follow-up schemes, and perform operational check of system. Verify dew point of instrument air to system.

13.4.4.8 Fire Protection

Check and/or calibrate all instrumentation, pumps, engines, piping, and follow-up schemes, and perform operational check of system. Verify spray patterns of automatic initiated deluge on ventilation exhaust filters.

13.4.4.9 Circulating Water System

Check and/or calibrate pumps, valves, and instrumentation interlocks, and check system operations.

13.4.4.10 Condensate and Feedwater System

Check and/or calibrate pumps, valves, piping, instrumentation, controls, interlocks, trips, water quality, and condensate demineralizer operation.

13.4.4.11 Primary Containment Cooling System and Purging System

Verify operability of fans and coolers in drywell. Check and/or calibrate instrumentation associated with containment pressure, temperature, suppression pool level, purging pressures, and flow rates.

13.4.4.12 Area and Process Radiation Monitoring Systems

Check and/or calibrate radiation monitoring instrumentation not related to nuclear safety. These monitors include liquid and process radiation monitors, area monitors, and personnel monitors.

13.4.4.13 Fuel Pool Cooling and Cleanup System

Check and/or calibrate instrumentation, valves, pumps, heat exchangers, filters, and demineralizer, and verify operability of system. The spent-fuel pool will be filled with demineralizer water, checked for leakage, and the pool and surge test instrumentation will be checked.

13.4.4.14 <u>Heating, Ventilating, and Air-Conditioning</u>

Check and/or calibrate instrumentation, valves, pumps, fans, heaters, coolers, dampers, louvers, and other equipment associated with these systems. Verify operability of systems.

13.4.5 REACTIVITY CONTROL SYSTEMS TESTS

13.4.5.1 <u>Control Rod Drive (CRD) Hydraulic System</u>

13.4.5.1.1 Prerequisites

- *All piping and wiring installed and connected.*
- *System flushed and cleaned per specifications.*
- *Demineralizer water available in demineralizer water reservoir.*
- *CRD hydraulic supply pumps operational.*
- *Instrument air available.*
- *The ac and dc power available.*
- *Power available through reactor safety circuit to energize scram valves.*

13.4.5.1.2 Test Objective and Summary

A. *Calibrate instruments.*

B. *Check alarms, controls, and interlocks.*

C. *Obtain pump performance data, e.g., head, flow, suction pressure, bearing and cooling-water temperatures, motor current, and RPM. (See manufacturer's instruction book for special requirements.)*

   NOTE: This portion of the preoperational test is performed much earlier than the remainder of the test because the pumps are used for the flushing listed in the prerequisites.

D. *Adjust flow control valves.*

E. Check operation of proper valves from appropriate selector switches, interlocks, or trip signals including:

- *Scram valves and scram solenoid pilot valves.*
- *Scram backup pilot valves.*
- *Scram volume dump and vent valves.*
- *Drive selection valves; withdraw and insert control.*

F. After drives are installed, adjust individual flow control valves for proper drive speeds.

G. Monitor and record total system performance data with all drives installed, including:

- *Cooling water flow.*
- *Total system flow.*
- *Flow returned to reactor.*
- *System pressures.*
- *Transient response of system during insert and withdraw operations or following scrams.*

13.4.5.2 CRD Tests

CRD hydraulic system and control system tests are completed before beginning tests of individual CRD mechanisms. All internals are in reactor, including guide tubes and thermal sleeves. Install blades and dummy fuel assemblies. Test objectives and summary for individual drives:

- *Insertion-continuous and by notch.*
- *Withdrawal-continuous and by notch.*
- *Stroke timing.*
- *Scram time measurements.*
- *Check proper position indication and in/out limit lights.*
- *Repeat those tests in the hydraulic system and manual control system which are required to verify total system performance.*

- *Recheck rod control interlocks.*

- *Test safety circuit in conjunction with control rod system to verify scram signals and rod withdrawal interlocks from all safety circuit sensors.*

*13.4.5.3 **Standby Liquid Control System Test***

All portions of this test, except the actual pumping rate into the reactor (item E) may be done at any time regardless of the status of the reactor vessel (full or empty, head on or off). Test objectives and summary:

A. *Calibrate instruments and check setpoint.*

B. *Fill the standby liquid control solution tank with demineralizer water and operate the injection pumps, recirculation to the tank.*

C. *Check the setpoint of the pump discharge relief valves.*

D. *Check the control circuits for the explosive injection valves thoroughly before connecting to the valves. Use a dummy resistance to simulate the valve during the circuit checkout.*

E. *Turn the key lock switch to each channel to fire the explosive valve and start the injection pump. Measure pumping rates into the reactor.*

F. *Check the interlock with the reactor water cleanup (RWC) system to ensure isolation when the standby liquid control system is actuated.*

G. *Check operation of the standby liquid control solution temperature controls and air spargers.*

H. *Fill the test tank with demineralizer water and operate the injection pumps in simulated test mode, recirculation to the test tank.*

I. *After the system has been demonstrated by the foregoing tests, replace the valve explosive cartridges. Very shortly before fuel loading, add the required boron chemical to the standby liquid control solution tank. Mix and sample.*

13.4.6 REACTOR AND CORE STANDBY COOLING SYSTEMS

*13.4.6.1 **Reactor Vessel Component***

Calibrate and test reactor vessel o-ring leak detection instrumentation.

13.4.6.2 Reactor Vessel and Reactor Coolant System Hydro Test

This test is completed at the earliest possible date to permit installation and testing of CRD mechanisms and reactor internals.

13.4.6.2.1 Prerequisites

A. Installation of the reactor vessel, all drive and instrument thimbles, and blind flanges.

B. All nuclear system piping installed to the first valve. The shutdown system and emergency cooling systems (which are closed loops) should be completed to permit chemical cleaning concurrently with the primary system.

C. Recirculation piping will be complete.

D. Source of heating available for raising reactor metal temperatures to a minimum of 123°F. This may be the steam supply from the station auxiliary startup boiler.

E. Reactor vessel filled with demineralizer water for the hydro test.

F. Other interconnected systems completed to the first valve, and preferably beyond, to include the high-pressure portions since the chemical cleaning immediately following reactor hydro testing requires completed systems.

13.4.6.2.2 Test Objective and Summary

A. Heat reactor vessel to required temperature using mononuclear steam supply and recirculation the reactor water with the residual heat removal (RHR) pumps.

B. Hydro test reactor, main steam lines, and recirculation loops to 1560 psig.

C. Inspect all field welds to reactor vessel nozzles, piping, and valves included in the limits of this hydrotest.

13.4.6.3 Reactor Recirculation System

This test will determine recirculation loop (recirculation pumps and jet pumps) characteristics to the degree possible with cold water conditions.

13.4.6.3.1 Prerequisites

A. 4160-V electrical power must be available.

B. 575-V electrical power must be available.

C. Reactor hydrotest and chemical cleaning has been completed.

D. Water must be in the vessel during pump tests.

13.4.6.3.2 Test Objectives and Summary

A. Operate all recirculation loop valves.

B. Calibrate loop instrumentation and check controls and interlocks.

C. Operate recirculation pumps and motor-generator (MG) sets at reduced speed.

D. Check flow control transient operation within the range permitted by cold water and atmospheric pressure in reactor. Optimize controller settings for system linearity and response time requirements.

E. Perform a jet pump consistency test.

13.4.6.4 Nuclear System Safety and Relief Valves

Test objectives and summary:

A. Safety valves will be installed as received from the factory, where setpoints were adjusted, verified, and indicated on the valve.

B. Verify proper operation of remote controlled relief valve solenoids from MCR.

C. Check automatic blowdown function of the relief valves with a simulated pressure signal.

13.4.6.5 Reactor Core Isolation Cooling (RCIC) System

This shutdown cooling system requires steam to drive the turbine pump. The valves and controls operate from the station battery and may be tested at any convenient time in the preoperational test schedule. The turbine pumping test is deferred until steam is available during the startup test.

13.4.6.6 High-Pressure Coolant Injection (HPCI) System

Test objectives and summary:

A. This test will check out the functional capability of all components needed to operate under simulated accident conditions and under various failure modes. Final operation and full *capacity testing of the HPCI system may be deferred until adequate steam supply is available during startup testing.*

B. *All components of the system will be checked during the test including the turbine, pump, valves, and associated instrumentation.*

C. *The suction will be aligned alternately from the condensate storage tank and from the suppression pool to assure the proper operation of these sources.*

D. *This preoperational test will verify that the system logic satisfies its design objective and will also furnish reference characteristics such as differential pressures and flowrates that can be used as basepoints for checking measurements in subsequent testing of the system.*

13.4.6.7 Core Spray (CS) System

The prerequisites for testing the CS system is that the vessel head and shroud head are removed for observation, and the vessel is ready to receive water.

13.4.6.7.1 Test Objectives and Summary

A. *Calibrate all instrumentation.*

B. *Check alarms, controls, and interlocks including complete verification of automatic system starting controls.*

C. *Operate pumps by recirculating to the torus in the test mode. Verify pump and system performance from manufacturer's head flow curves and measured system pressures.*

D. *Check operation of all motor-operated valves.*

E. *With valves closed and locked out of service, initiate system automatically and verify pump start.*

F. *With pumps locked out of service, initiate system automatically and verify that valves open. Repeat for system in test configuration.*

G. *Isolate pump suction from torus and route to receive pump supply directly from condensate storage tank. Spray into reactor vessel. Verify proper flowrate and observe spray pattern. This will also be repeated with suction from the torus.*

H. Simulate the accident condition simultaneously with a power failure and observe proper sequential operation of system pumps and valves. This test is run concurrently with the containment cooling system automatic operation

13.4.6.8 <u>RHR System - Low-Pressure Coolant Injection (LPCI) Mode, Containment Spray Mode, and Shutdown Cooling Mode</u>

The LPCI, containment spray, and shutdown cooling modes of the RHR system will be tested. The test is designed to verify all the logics, interlocks, automatic initiations, and automatic isolations of the modes individually. Then where mode interfaces occur, the interlocks or blocks will be tested under as near actual conditions as possible. However, at no time will flow be permitted into the drywell.

13.4.6.8.1 Prerequisites

Water must be in the torus.

13.4.6.8.2 Test Objectives and Summary - Valve Test

A. LPCI - All valves in the system will be cycled from the control room and the local control panels. Proper operation and indications will be verified.

B. Containment spray - During this test, all precautions will be taken to ensure no water is introduced into the drywell. The valves in the system will be exercised as above with the same verifications.

C. Shutdown cooling (including reactor head spray) - All valve actions will be verified as above. No special precautions are required for this test as long as torus water has not been allowed into the RHR system.

13.4.6.8.3 Test Objectives and Summary - Logic and Interlock Test

A. LPCI - This test will verify initiation logic, automatic isolation, and valve and pressure interlocks. Signals will be simulated to cause an automatic initiation signal to the LPCI system. The start signal will be introduced into the system under both normal auxiliary power and standby diesel generator conditions to verify required valve and pump sequencing.

B. Containment spray - This manually initiated system has only a reactor pressure vessel (RPV) level interlock associated with it. The suction valves to the pump interlocks having been checked in the preceding test make it unnecessary to reverify this step.

C. Shutdown cooling (including reactor head spray) - This test will verify the automatic isolation of the shutdown cooling system on high drywell pressure or low reactor water level. No attempt will be made to verify the heat removal capability of the RHR heat exchangers until sometime during the startup test program. The RHR service water valves to the heat exchangers will be checked at this time as part of the system. The system will be used operationally prior to that time, however, to support other tests where it is necessary to control the reactor water temperature.

13.4.6.8.4 Test Objective and Summary - System Test

A. LPCI - The LPCI system will be started using a simulated automatic initiation signal. After flow has been established through the system by operation of the pumps and valves, the system operating characteristics will be established for one-, two-, three-, and four-pump operation.

B. Containment spray - No water flow will be used to verify flow through the containment spray drywell sparger. Compressed air or nitrogen will be introduced into the sparger from the first upstream test connection.

NOTE: The remainder of the system must be isolated during this test.

Using a smoke bomb or flags, verify flow through each nozzle (actual nozzle flow will have been determined by bench testing at nozzle manufacturer's facilities). To verify flow through the remainder of the system, both isolation valves for each sparger must be locked closed and flow diverted through a test line. At this time the containment spray torus sparger flow will be verified.

C. Shutdown cooling (including reactor head spray) - The RHR system will be set up at this time to take its suction from the RPV at the recirculation pump inlet. The system, placed into the normal configuration for shutdown cooling operations, will be started according to unit operating procedures. Pumps will be operated singularly to ensure proper pump flow paths. All interlocks having been checked in previous tests, only the determination of the system's flow test, the flow path, and operability of the reactor head spray will be verified.

D. All sensors of the RHR system will have their calibrations, alarms, or trip points verified during this test. Proper annunciations will be verified at both the control room and local panels.

13.4.6.9 Reactor Water Cleanup (RWC) System Test

The RWC system will be flushed, cleaned, and initially checked out while the reactor vessel is empty for the installation of drive mechanisms, by supplying it with condensate and routing the discharge either to the radwaste system or to the condenser hotwell. However, the RWC system cannot be completely checked during the preoperational phase because full temperature and pressure conditions are required in the reactor for normal system operation to complete the tests. The filter-demineralizer must either be bypassed or operated only when precoated.

13.4.6.9.1 Prerequisites

A. The ac power from auxiliary bus must be available.

B. The ac and dc control power must be available.

C. Reactor water must be available for auxiliary pump suction.

D. Instrument air must be available.

13.4.6.9.2 Test Objectives and Summary

A. Check operation of cleanup pump.

B. Check operation of pressure control station to the hotwell and the liquid radwaste system by simulating pressure input signals.

C. Check operation of the main cleanup pumps by pumping first to the hotwell or to the radwaste system and then to the reactor. Do not pump to the reactor until filters and demineralizer are fully checked out to prevent injecting poor quality water into the reactor.

D. Check operation of filters, demineralizers, and all associated equipment. Perform all required operations, such as precoating, normal operation, standby recirculation, filter aid addition, and backwash. Be sure that the system is set up such that filter breakthrough will not dump impurities into the reactor (preferably routed to the radwaste system for initial operation).

E. Check operation of all valve and pump interlocks by simulating signals to appropriate instrumentation.

F. Check calibration and alarm or trip (interlock) setpoints of all instrumentation.

G. After the system is proven to be operational in all modes which are possible to demonstrate without an elevated pressure or temperature in the reactor, charge the filter-demineralizers and place the system in normal service. Charging must be accomplished when water is admitted in the reactor during preoperational testing.

13.4.7 PRIMARY CONTAINMENT TESTS

13.4.7.1 Primary Containment Leak Rate Measurement and Overpressure

13.4.7.1.1 Prerequisites

A. All piping and electrical penetrations must be in place.

B. Testing described in this procedure must be performed in sequence:

- *Individual penetration leak rate measurements.*
- *Isolation valve operating tests.*
- *Valve seat leakage measurements.*
- *Design pressure tests (may precede 2 and 3).*
- *Combined leak rate measurement.*

C. All isolation valves must be fully operable.

D. Containment and CS system must be complete and operable.

E. During the combined leak rate measurement, no equipment shall be operating within the containment and no heat sources shall be energized, nor shall hot or cold fluids be circulated.

F. A complete survey must be made to locate and remove any instrumentation, light bulbs, etc., which could be damaged by external pressure.

13.4.7.1.2 Test Objectives and Summary

A. Check testable penetrations by applying air pressure and checking with soap suds.

B. Stroke all containment isolation valves and leave in closed position.

C. Pressurize to 14 psig and check all penetration welds made subsequent to design pressure test with soap suds.

D. Pressurize to calculated peak pressure (46.5 psig) and conduct leak rate measurement.

13.4.7.2 <u>Isolation Valves Leak Rate Measurement</u>

13.4.7.2.1 Prerequisites

A. All isolation valves and connected piping have been installed and hydrotested from the reactor vessel to the outside isolation valve.

B. All piping hangers, guides, and anchors (which affect the isolation valves) have been installed and set properly.

13.4.7.2.2 Test Objective

Measure leakage across the seat (inside the process line) of all isolation valves in the nuclear system.

13.4.7.3 <u>Standby Gas Treatment System (SGTS) and Reactor Building Negative Pressure</u>

Instrumentation and controls will be calibrated and interlocks will be checked. Blowers will be operated to check flow capacity and their ability to maintain negative pressure in the reactor building. Automatic isolation of the reactor building and initiation of the SGTS will be verified. The absolute and charcoal filter collection efficiency will be measured.

13.4.8 INSTRUMENTATION AND CONTROLS TESTS

13.4.8.1 <u>Instrumentation for Reactor Protection System</u>

13.4.8.1.1 Prerequisites

A. All safety system sensors have been installed and calibrated.

B. All wiring has been installed and checked for continuity.

13.4.8.1.2 Test Objectives and Summary

A. Operate the MG sets to check capacity and regulation.

B. Energize buses, check controls and power source transfer.

C. Check operation, pickup, and dropout voltages of the protection system relays.

D. Check each safety sensor for operation of proper relay.

E. Using test signals, verify scram setpoints. Check proper operation of level switches by varying water level against a suitable reference point such as the vessel flange.

F. Check all positions of the reactor mode switch for proper interlocks and bypass functions.

G. Check automatic closing of all isolation valves from proper signal.

H. Check automatic initiation of relays and contacts for CS, HPCI, LPCI, automatic depressurization, and other plant protection systems by the proper signal.

13.4.8.2 <u>Neutron and Gamma Radiation Instrument Systems</u>

13.4.8.2.1 Systems

- *Source range monitoring (SRM) subsystem and chamber drives.*
- *Intermediate range monitoring (IRM) subsystem and chamber drives.*
- *Local power range monitoring subsystem.*
- *Average power range monitoring subsystem.*
- *Traversing incore probe (TIP) subsystem.*
- *Area radiation monitoring system.*
- *Process liquid and gas monitors.*

13.4.8.2.2 Test Objectives and Summary

The following types of preliminary testing are required (where applicable) prior to fuel loading:

A. Check continuity and resistance to ground of all signal and power cables.

B. Check response and calibration of all channels with simulated input signals.

C. Check alarm and trip setpoints.

D. Check chamber response to bugging sources.

E. Check all interlocks with the reactor manual control system (RMCS).

F. Check operation and position indication of all SRM-IRM chamber drives.

G. Using a dummy TIP chamber, insert the calibration probe in all incore calibration tubes. Verify capability to insert more than one calibration probe in the cross-calibration guide tube.

H. Install all incore SRM and IRM chambers and verify final system operability.

13.4.8.3 Process Computer System (Rod Worth Minimizer Function)

After the CRD system is operational, withdraw control rods in various sequences to expose the rod worth minimizer (RWM) function of the process computer to simulated operational conditions and withdrawal patterns.

13.4.8.3.1 Test Objectives and Summary

A. The RWM function will be checked using a test program. The RWM will be tested simulating an increasing and a decreasing power.

B. Attempt improper rod withdrawal at various points in the withdrawal sequence, and verify that the action is blocked.

C. Determine capability to insert drive mechanisms out of sequence to the extent permitted by the RWM function.

D. Check all alarms by simulated or actual error conditions:

- *Lower power alarm.*
- *Printing.*
- *Computer error.*
- *Input/output error.*
- *Select error.*
- *Select block.*
- *Insert block.*
- *Withdraw block.*

E. Check all displays and information printout:

- *Group identification.*
- *Withdrawal error readout.*
- *Insertion error readout.*
- *Print out rod position from scan and memory for several rod withdrawal patterns.*

13.4.9 ELECTRICAL SYSTEM TESTS

13.4.9.1 Standby ac Power System

After instrumentation and controls are installed and calibrated and wiring is checked, the capability of each diesel generator to pickup CS, RHR, cooling water pumps, and associated emergency loads in sequence will be demonstrated. Each diesel generator will be tested for load carrying capability. All interlocks, automatic initiation, and followup schemes on the auxiliary and shutdown transformers will be tested as part of those tests.

13.4.9.2 The dc Power System

Check and/or calibrate relays, instruments, breakers, interlocks, and other electrical components. Verify battery charger and battery discharge rate.

13.4.9.3 The ac Auxiliary Power System

Check and/or calibrate all protective devices, interlocks, followup schemes, and other electrical components. Verify insulation quality and/or circuit continuity and functional operation.

13.4.9.4 Plant Communications System

Check operation of each handset, phone jack, telephone, and public address speaker. Adjust speakers for proper volume and orientation. Ensure proper operation of the radiation emergency alarm.

13.4.10 RADWASTE SYSTEMS TESTS

13.4.10.1 Gaseous Radwaste System Test

13.4.10.1.1 Prerequisites

Construction is completed; air and electric power is available for all control devices.

13.4.10.1.2 Test Objectives and Summary

- *A. Check automatic operation of isolation valves.*
- *B. Calibrate and set trip point of all instrumentation and alarms.*
- *C. Check out filter performance test system.*

13.4.10.2 Liquid and Solid Radwaste Systems Tests

After fuel is loaded in the reactor, all drains from the reactor spent-fuel pool or interconnecting auxiliary systems must be considered to be potentially radioactive. Therefore, most of the liquid radioactive waste disposal system must be operational prior to fuel loading and must be tested prior to bolting the RPV head. The solid radwaste handling system need not be operational before fuel loading.

13.4.10.2.1 Test Summary

- *A. Calibrate instrumentation.*
- *B. Check all controls and interlocks.*
- *C. Recheck all air-operated valves.*
- *D. Pumps and tanks.*
  - *1. Clean tanks mechanically.*
  - *2. Fill with demineralized water.*
  - *3. Check pump operation in recirculation, whenever possible.*

4. *Simulate operations associated with the particular tank, such as draining or filling, recirculating, sampling, and processing to a filter, demineralizer, another tank, or overboard discharge.*

E. *Liquid radwaste system.*

1. *Simulate all required operations, running a complete cycle without resins.*

2. *Check procedures and equipment performance.*

F. *Solid radwaste handling, storage, and disposal.*

Check drum handling, loading, and capping, and transfer to storage.

13.5 FUNCTIONAL TEST PROCEDURES

Prior to fuel loading, it is necessary to verify that the plant is ready for fuel loading. This is accomplished by signing off the preoperational test instructions as being completed and performing a series of checkout type functional tests. Most of these functional tests are contained in the plant operating procedures manual as surveillance tests. Several of these functional tests are special and must be performed prior to fuel loading or during the power test program. These are as follows:

13.5.1 LOSS OF POWER DEMONSTRATION - EMERGENCY CORE COOLING REQUIRED

This test will demonstrate the capability of the emergency diesel generators to auto start and assume all of their respective core standby cooling loads on a loss of all external ac power with a loss of one of the two dc power suppliers to the core standby cooling system.

13.5.2 COLD AND HOT FUNCTIONAL TESTS

Formal documentation will be made of operator training on system operation and system operation performance under hot conditions.

13.5.3 COLD FUNCTIONAL TESTING

The cold functional test period has been set aside to allow for integrated systems operation, insofar as is possible, prior to fuel load. During this time it is intended to observe for any unexpected operational problems from either an equipment or procedural source and to provide an opportunity for operator training. Each of the regular rotating shifts will be required to operate and manipulate certain systems on a formal basis. For these systems a signoff line is provided which will be the controlling document to ensure completion of these training requirements.

13.5.4 HOT FUNCTIONAL TESTING

Since many plant systems will be exposed to their operating environment for the first time during the first heatup to full pressure, their performance as well as the adequacy of the plant operating procedures should be verified as early as possible. The hot functional test is intended to accomplish this requirement. This summarizes the testing to be performed during the initial plant heatup pressurization and low power operational phases. The incorporation of all of these tests into one document ensures that the startup will be made in a controlled, orderly fashion, and that the integrated performance of the combined systems necessary to accomplish nuclear power operation will be assessed before proceeding to operation at higher power levels.

13.6 STARTUP AND POWER TEST PROGRAM

13.6.1 PROGRAM DESCRIPTION AND OBJECTIVES

13.6.1.1 General

The tests comprising the startup and power test program are conducted primarily to show that the overall plant performance is confirmed in terms of established design criteria. These criteria and the associated tests have either a safety or economic orientation, while often both aspects of the design are being explored. A most important result of the startup test program is that the operator has available to him valuable data upon which the future, normal, and safe operation of the plant can be based. The startup and power test program may be divided into the following discrete and successive groups of tests:

- *Fuel loading and shutdown power level tests.*
- *Initial heatup to rated temperature and pressure.*
- *Power testing from 25% to 100% of rated output.*
- *Warranty demonstrations.*

The tests performance can be broadly classified as major plant transients (table 13.6-1), stability tests (table 13.6-2), and a residue of tests directed towards demonstrated correct performance of the numerous auxiliary plant systems; clearly, certain tests may be identified with more than one class. Each test is discussed later, but at this juncture the following comments are given by way of outlining the startup and power test program. Table 13.6-3 shows the complete startup and power test program and should be considered in conjunction with figure 13.6-1, which shows graphically the various test points as a function of core thermal power and flow. It is expected that in the elapsed time before embarking upon the startup test program, it may well be necessary to modify the scope of the program and/or the content of individual tests in order to utilize experience gained from earlier startups. If such modifications do not affect the safety or the safety analysis of the plant the program may be altered from the program presented here. If such modifications offset safety, they will be treated as standard amendments to the Final Safety Analysis Report (FSAR).

Response

The initial startup test program described herein conforms closely to the requirements identified in the commission's Guide for Planning of Initial Startup Test Programs. Two areas in which conformity is not afforded are:

- *Measurement of moderator temperature reactivity defect and power defect.*
- *Determination of critical control rod configuration vs predicted.*

A discussion of the reasons for these nonconformities is given below.

Measurement of Reactivity Defects

A. *Physics parameters such as temperature coefficients, void coefficients, power coefficients, and control system worths are chosen by design for safety and ease of operation of the nuclear reactor. These parameters ultimately determine the ease of starting up, maneuvering, and shutting down the reactor. They directly affect the rate and maximum values of reactor pressure and reactor power during various reactor transients and excursions.*

B. *In the startup testing of a plant, two methods may be considered for verifying the adequacy and design of the core concerning the above parameters:*

   1. *Assume the design models are adequate, measure the parameters as directly as possible, and compare their value with the design values.*

   2. *Establish a progressive startup program in which the safety of each phase is assured by the successful results of a previous phase whereby the effects and adequacy of the physics parameters, in conjunction with the design model, are determined by measuring response characteristics of reactor pressure and reactor power during plant transients. In addition, during the startup program, demonstrate the relative ease of operability and maneuvering of the reactor.*

   It has been General Electric (GE) practice to regard view 2 above as necessary and sufficient for all plants utilizing a core design which has previously been proven in earlier plants. View 1 is only used on plants utilizing a new reactor design or sufficient deviation from a proven design as to raise questions concerning the degree of adequacy of the design model. In any event, 1 is not sufficient and is always used in conjunction with 2.

C. *Verification of reactivity characteristics of core components and to some extent, verification of calculational models can be obtained by minimum critical core loading tests. Sufficient verification of the calculational model can generally be obtained without minimum critical loadings through a startup program characterized by B2. It has also been shown that the testing of nuclear properties of core components in the field is not necessary. This conclusion is documented in NEDE-10017, Field Testing Requirements for Fuel Curtains and Control Rods, D.R. Jones and T.G. Harsum, June 1969. (This document is presently under revision to supply additional confirmation and data supporting the conclusion.) Consequently, in view of these considerations, GE does not regard minimum critical loadings as required, in general, and would specify these tests only in special cases of obtaining physics data for a new design and/or to establish reliability in the quality assurance regarding the gross nuclear properties following changes in the manufacturing of the components or in the manufacturing of a new type of component.*

<u>Critical Control Rod Configuration versus Predicted</u>

The only meaningful criteria for initial criticality is one which requires the attainment of criticality. Stating a criteria in terms of an "estimated critical position" is more of a criteria on the calculations than on the test. The most creditable use of an estimated critical position is to provide operations personnel with a reactivity goal on a known core to help minimize operator errors. An estimated critical position during initial criticality can serve as a guide to the test engineer and a value for this purpose will be provided. However, it should be emphasized that an estimated critical position during initial criticality does not have any safety merit or operational merit and can, in fact, pose a situation of concern in which less than maximum attention is afforded rod motions a considerable margin below estimated critical position.

In order to foster the required attention desirable for initial criticality, the operations personnel should be instructed to expect criticality on the next successive rod increment to be withdrawn. It is not considered to be required or desirable to state criteria in the initial criticality test to judge whether the reactor core is completely satisfactory or not. The entire testing program provides the necessary criteria to perform this judgment and the ultimate test to judge the core and the entire nuclear steam supply system (NSSS) is the 100-h demonstration run.

13.6.1.2 <u>Fuel Loading and Shutdown Power Level Tests</u>

Fuel loading requires the movement of the full core complement of assemblies from the fuel pool to the core with each assembly identified by number before being placed in the correct core coordinate position. The procedure controlling this movement is arranged so that shutdown margin and subcritical checks are made at predetermined intervals throughout the loading, thus ensuring safe loading increments. Specially sensitive neutron monitors situated at suitable locations within the reactor vessel serve to provide indication for the shutdown margin demonstrations and also allow the recording of the core flux level as each assembly is added. A complete check is made of the fully loaded core to ascertain that all assemblies are properly installed, correctly oriented, and occupying their designated positions.

At this point in the program, a number of tests are conducted which are best described as initial shutdown power level tests. Chemical and radiochemical tests are made in order to check the quality of the reactor water before fuel is loaded and to establish base and background levels which will be required to facilitate later analysis and instrument calibrations. Plant and site radiation surveys are made at specific locations for later comparison with the values obtained at the subsequent operating power levels. Shutdown margin demonstrations are repeated for the fully loaded core, and criticality is achieved in turn with each of the prescribed rod sequences, data being recorded for each rod withdrawn. The reactor is made critical by means of each control rod sequence using the normal source range monitors (SRMs) in conjunction with the operational sources in order to show that adequate response exists for normal operation. Each control rod drive (CRD) is subjected to scram and friction testing at ambient conditions. An initial setting is given to the intermediate range monitors (IRMs). The process computer is checked to see that it is receiving correct values for those process variables which are available.

13.6.1.3 Initial Heatup to Rated Temperature and Pressure

Heatup follows satisfactory completion of the shutdown level tests and further checks are made of coolant chemistry together with radiation surveys at the selected plant locations. All CRDs are scram timed at rated temperature and pressure with selected drives timed at intermediate reactor pressures and for different accumulator pressures. The control rod sequences are further investigated in order to obtain rod pattern versus temperature relationships. The process computer checkout continues as more process variables become available for input. The reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems will undergo controlled and quick starts at low reactor pressure and at rated conditions. Correlations are obtained between selected process temperatures at several locations and the values of other process variables as heatup continues. The movements of drywell piping systems as a function mainly of thermal expansion are recorded for comparison with design and installation data. A preliminary average power range monitor (APRM) calibration is made using coolant temperature rise data during nuclear heatup.

13.6.1.4 Power Testing From 25% to 100% of Rated Output

The power test phase comprises the following tests, many of which are repeated several times at the different test levels. It must be appreciated that while a certain basic order of testing is maintained, there is nevertheless considerable flexibility in the test sequence which may be used whenever it becomes operationally expedient.

Coolant chemistry tests and radiation surveys are made at each principal test level in order to preserve a safe and efficient power increase while maintaining reactor water quality and local radiation levels within specified limits. Selected CRDs are scram timed at various power levels to provide correlation with the initial data. The effect of control rod movement on other parameters, e.g., electrical output, steam flow, and neutron flux level is examined for different power conditions. Following the first reasonably accurate heat balance (25% power) the power range nuclear instruments are calibrated. At each major power level (25%, 50%, 75%, and 100%)[a] the local power range monitors (LPRMs) are calibrated, while the APRMs are calibrated at each new power level initially, and following each LPRM calibration. Completion of the process computer checkout is made for all variables and the various options are compared with other proven methods of calculation as soon as significant power levels are available. Further tests of the RCIC and HPCI systems are made with and without injection into the reactor pressure vessel (RPV). Collection of data from the system expansion tests is completed for those piping systems which had not previously reached full operating temperatures. The axial and radial power profiles are explored fully by means of the traversing incore probe (TIP) system at representative power levels (25%, 50%, 75%, and 100%)[a] during the power ascension. Core performance evaluations are made at all test points above the 10% power level and for selected flow transient conditions; the work involves the determination of core thermal power, maximum fuel rod surface heat flux, and the minimum critical heat flux ratio (MCHFR).

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a. These levels are nominal and variations of 5% in power are common and sufficient in defining the actual test level with the qualification that 100% power will not intentionally be exceeded.

Overall plant stability in relation to minor perturbations is shown by the following group of tests which are made at most test points:

- *Flux response to rods.*
- *Pressure regulator setpoint change.*
- *Water level setpoint change.*
- *Bypass valve opening.*
- *Flow control.*

For the first of these tests a centrally located control rod is moved and the flux response noted on a selected LPRM chamber. The next two tests require that the changes made should approximate as closely as possible a step change in demand, while for the two remaining tests a bypass valve is opened as quickly as possible and flow control setpoint changes are made, respectively. For all of these tests the plant performance is monitored by recording the transient behavior of numerous process variables, the principal one of interest being neutron flux. Other imposed transients are produced by dropping a feedwater heater and failing the operating pressure regulator to permit takeover by the backup regulator. Table 13.6-2 indicates the power and flow levels at which all these stability tests are performed.

The category of major plant transients includes full closure of all the main steam isolation valves (MSIVs), full closure of one MSIV at selected power level, fast closure of the turbine-generator control valves, fast closure of turbine-generator stop valves, loss of the main generator and offsite power, tripping a feedwater pump, and several trips of the recirculation pumps. The plants transient behavior is recorded for each test and the results may be compared with the predicted design performance. Table 13.6-1 shows the operating test conditions for all the proposed major transients.

A test is made of the relief valves in which the capacity and general operability is demonstrated. At all major power levels, flow calibrations are made.

The as-built characteristics of the recirculation pump drives are investigated as soon as operating conditions permit full core flow. The local recirculation speed control loop performance, based on the drive motor, fluid coupler, generator, drive pump, jet pumps, and control equipment is checked. The vibration testing conducted at the cold flow condition is extended to measurements at several power conditions as the operating power level is raised.

During power testing the plant will be returned to shutdown. This procedure outlines the various steps to shutdown. The steps listed are to be regarded as a checklist to ensure that the plant is shut down in a systematic manner.

A. Preshutdown Preparations

1. Fill and vent the reactor shutdown cooling system.

2. *Start the turbine bearing lift pumps and run for about 10 min to check their performance.*

3. *Check the automatic start capability of the following turbine oil pumps:*

    - *Turning gear oil pump.*

    - *Emergency turbine bearing oil pump.*

    - *Main shaft suction pump.*

4. *Check that the rod worth minimizer (RWM) is not bypassed.*

5. *Select the desired control rod sequence.*

B. *Shutdown Procedure*

1. *Reduce power to ~ 60% of rated, (initial conditions are 100% power and 100% core flow) with recirculation pump master controller.*

    a. *Continuously observe APRMs and recirculation flow decreasing, and stop load reduction when APRMs read 60%.*

    b. *Observe that core flow is ~ 50% rated.*

2. *Transfer recirculation pump master flow controller to manual.*

    a. *Switch to balance.*

    b. *Null deviation with manual potentiometer.*

    c. *Switch to manual.*

3. *Insert control rods in reverse of the withdrawal sequence until a power level of ~ 40% of rated is reached.*

    a. *Open HP heater extraction drain valves.*

    b. *Close HP heater extraction valves.*

    c. *Insert control rods as required to compensate for reactivity increase due to the colder feedwater.*

    d. *Check that HP heater levels are stabilized and at setpoint levels. Levels may be expected to change slightly when closing extraction valves if steam flow to turbine has been changing.*

4. *Reduce power to 20% of rated with control rods.*

    a. *Insert control rods in reverse of the withdrawal procedure until a power level slightly < 20% of rated is reached.*

    b. *Observe that recirculation pumps are set back automatically to 20% speed as feedwater decreases to < 20%.*

5. *Shut down one condensate, booster, and feedwater pump.*

    a. *Set feedwater pump select switch to off.*

    b. *Select which feedwater pump will be shut down.*

    c. *Trip the feedwater pump selected in the previous step by moving its control switch to trip and release.*

    d. *Set condensate and booster pump select switch to off.*

    e. *Trip the selected condensate pump. This will also trip the associated booster pump.*

    f. *Put a condensate and booster pump on standby with the condensate and booster pump select switch when the condensate and booster pump discharge header pressures have stabilized.*

6. *Remove LP feedwater heaters from service.*

    a. *Check that heater levels stabilize at the setpoint level.*

    b. *Insert control rods as required to compensate for reactivity increase due to the colder feedwater.*

    c. *As power level approaches 10%, check that control rod positions are in accordance with RWM sequence latched.*

7. *Transfer house load to reserve power transformer.*

8. *Transfer the feedwater control from automatic to manual, as follows:*

    a. *Open feedwater manual loading valve. The vessel level will rise slightly, closing the automatic feedwater regulating valve.*

    b. *When the steam flow is sufficiently below 10%, as control rods are inserted, the reactor water level will rise with the automatic valve closed, and the level must be manually controlled with the manual loading valve.*

9. Insert control rods until power (as indicated by APRMs) is ~ 5%.

10. Install all IRMs, as follows:

   a. Check that at least three IRM channels in each scram channel are operative. Observe:

      - *Bypass switch positions.*
      - *Bypass indicating lights.*
      - *Inoperative indicating lights.*

   b. Position all range switches to the least sensitive range.

   c. Fully insert all operative IRM chambers.

   d. Adjust range switches, so all recorders read on scale.

   e. As power is decreased, maintain the IRM channels on scale and below the high-flux rod block (0.85 of scale).

11. Separate unit from the system, as follows:

   a. Reduce the generator lead to ~ 1% with the load selector. The pressure regulator will now open the bypass valves to the condenser as the reactor steam flow exceeds the flow required by the turbine.

   b. Trip the turbine with the remote trip button. Operation of this trip will:

      - *Close all stop and control valves.*
      - *Close all intercept valves.*
      - *Close extraction check valves.*
      - *Open extraction drain valves.*
      - *Trip the generator main circuit breakers automatically when the stop valves close.*

12. Transfer reactor mode switch from run to startup.

13. Fully insert all control rods in reverse of the withdrawal sequence as follows:

   a. Change range switches on IRMs as required to keep all channels on scale.

b. Insert SRMs before IRM readings decay to lowest range.

14. Reduce primary system pressure as follows:

a. Start pressure reduction by reducing pressure regulator setpoint. Pressure regulator B setpoint remains ~ 10 psig above A at all times.

b. Plot cooldown rate versus time (recirculation loop A inlet temperature) to ensure that the cooldown rate of 100°F/h is not exceeded.

c. Observe vessel temperature during the entire cooldown to ensure that the WT limit of 75°F between the vessel wall and vessel flange is not exceeded.

15. Flooding reactor vessel is performed as follows:

a. At ~ 300 psig, begin slowly flooding the reactor vessel to assist cooling of the head area.

b. Observe the change in vessel water level. Adjust the feedwater manual loading valve to establish a slow rise in level.

16. Put the reactor auxiliary cleanup pump in service.

17. When the reactor pressure reaches 150 psig, the pressure regulator will no longer control the bypass valve opening. If it is necessary to continue cooldown by bypassing more steam [e.g., steam jet air ejector (SJAE) steam flow is not sufficient], the bypass valves may be opened with the bypass opening jack.

18. Put the shutdown cooling system in service when the reactor water temperature is 350°F.

19. Secure SJAEs when they are no longer effective in maintaining condenser vacuum.

20. At ~ 50 psig, shut down cleanup recirculation pumps.

21. Close MSIVs and steam line drain isolation valves.

22. Slowly increase reactor water level to above the head flange.

23. Put reactor head cooling system in service.

24. Open reactor vent valves when reactor pressure reaches atmospheric.

25. Shut down recirculation pumps A and B. Close the pump discharge valves to provide a better flowpath for the shutdown cooling system water. Leave the pump discharge bypass valves open to ensure that recirculation pumps cool down at the same rate as the balance of the primary system.

26. *Shut down remaining feedwater and booster pump as follows:*

    a. *Set feedwater pump select switch to off.*

    b. *Start auxiliary oil pump for remaining feedwater pump and trip feedwater pump as described earlier.*

13.6.1.5 Warranty Demonstrations

The final test phase consists of a warranty demonstration in which the steaming rate and quality can be shown to comply with contractual obligations.

13.6.2 DISCUSSION OF STARTUP AND POWER TESTS

13.6.2.1 General

All tests comprising the startup and power test program are discussed in paragraph 13.6.2.2 with reference to the particular test purpose, brief description, and statement of acceptance criteria where applicable. In describing the purpose of a test an attempt is made to identify those operating and safety oriented characteristics of the plant which are being explored.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either level 1 or level 2. A level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, component systems, or associated equipment. If a level 1 criterion is not satisfied, the plant will be placed in a suitable hold-condition until resolution is obtained. Tests compatible with this hold-condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the level 1 criterion are now satisfied.

A level 2 criterion is associated with expectations relating to the performance of systems. If a level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

For transients involving oscillatory response the criteria are specified in terms of decay ratio (defined as the ratio of successive maximum amplitudes of the same polarity). The decay ratio must be less than unity to meet a level 1 criterion and < 0.25 to meet level 2.

13.6.2.2 Test Purpose, Description, and Acceptance Criteria

(1) Chemical and radiochemical

Purpose

The principal objectives of this test are:

- *To maintain control of and knowledge about the quality of the reactor coolant chemistry.*
- *To determine that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the coolant chemistry meets water quality specifications and process requirements.*

Secondary objectives of the test program include data to evaluate the performance of the fuel, operation of the demineralizers and filters, condenser integrity, operation of the off-gas system, and calibration of certain process instruments.

Description

Prior to fuel loading a complete set of chemical and radiochemical samples will be taken to ensure that all sample stations are functioning properly and to determine initial concentrations. Subsequent to fuel loading, during reactor heatup and at each major power level change, samples will be taken and measurements will be made to determine the chemical and radiochemical quality of reactor water and reactor feedwater, amount of radiolytic gas in the steam, gaseous activities leaving the air ejectors, decay times in the off-gas lines, and performance of filters and demineralizers. Calibrations will be made of monitors in the stack, liquid waste system, and liquid process lines.

Criteria

Level 1 - Water quality must be known and must conform to the Technical Specifications at all times.

The activities of gaseous and liquid effluents must be known, and they must conform to license limitations.

Chemical factors defined in the Technical Specifications must be maintained within the limits specified.

(2) Radiation measurements

Purpose

- *To determine the background gamma and neutron radiation levels in the plant environs prior to operation in order to provide base data on activity buildup.*
- *To monitor radiation at selected power levels to assure the protection of personnel and continuous compliance with the guideline standards of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994) during plant operation.*

Description

A survey of natural background radiation throughout the plant site will be made prior to fuel loading. Subsequent to fuel loading, during reactor heatup, and at power levels of 25%, 50%, 75%, and 100% of rated power, gamma radiation level measurements and, where appropriate, thermal and fast neutron dose rate measurements will be made at significant locations throughout the plant. All potentially high radiation areas will be surveyed.

Criteria

Level 1 - The radiation doses of plant origin and occupancy times shall be controlled consistent with the guidelines of the standards for protection against radiation outlined in 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994).

(3) Fuel loading

Purpose

The purpose of this test is to load fuel safely and efficiently to the full core size.

Description

Prior to fuel loading, control rods will be installed and tested. A neutron source of $\sim 10^{13}$ *neutrons/s will be installed near the center of the core. At least three neutron detectors calibrated and connected in noncoincident mode to high-flux scram trips will be located to produce acceptable signals during loading.*

Fuel loading will begin at the most centrally located source and proceed radially to the fully loaded configuration. The following checks will be regularly performed as the core is loaded.

A. Subcriticality Check

A control rod surrounded by fuel in the vicinity of the cell to be loaded will be completely withdrawn; the core must remain subcritical. Then the rod will be reinserted.

B. Control Rod Functional Test

The rod in the loaded cell is completely withdrawn and reinserted.

NOTE: The functional test of the control rod in the cell just loaded serves also as the subcritical check for the next cell to be loaded, provided that the cell just loaded is surrounded on two sides by loaded cells.

Shutdown margin demonstrations will be performed periodically during fuel loading.

Criteria

Level 1 - The partially loaded core must be subcritical by at least 0.38% Δk/k with the analytically strongest rod fully withdrawn. The core is fully loaded and the full core shutdown margin demonstration has been completed.

(4) Shutdown margin

Purpose

The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

Description

This test will be performed in the fully loaded core at ambient temperature in the Xenon-free condition. The shutdown margin will be measured by withdrawing with the analytically strongest rod and one or more additional rods which have been calibrated by calculation until criticality is reached.

Criteria

Level 1:

A. *The shutdown margin of the fully loaded core with the analytically strongest rod withdrawn must be ≥ 0.38% Δk/k (plus an additional margin for exposure to be determined later).*

B. *If A cannot be satisfied, then the shutdown margin of the fully loaded core is satisfied if the reactor remains subcritical by ≥ 0.28% Δk/k (plus an additional margin for exposure to be determined later) during the sequential, complete withdrawal and insertion of every control rod within the core.*

(5) CRDs

Purpose

- *To demonstrate that the CRD system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating.*
- *To demonstrate that thermal expansion of core components does not bind or significantly slow control rod movements.*
- *To determine the initial operating characteristics of the entire CRD system.*

Description

The CRD tests performed during phases A through C of the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all CRDs operate properly when installed, they are tested periodically during heatup to assure that there is no significant binding caused by thermal expansion of the core components. A list of all CRD tests to be performed during startup testing is given below.

CRD System Tests

		Reactor Pressure (psig) (with core loaded)			
Test Description	*Preop Tests*	*0*	*600*	*800*	*Rated*
Position indication	*All*	*All*			
Normal insert/withdraw times	*All*	*All*			*4*[a]
Coupling	*All*	*All*[c]			
Friction		*All*			*4*[a]
Scram times (normal accumulator pressure)	*All*	*All*	*4*[a]	*4*[a]	*All*
Scram times (minimum accumulator pressure)		*4*[a]			
Scram times (zero accumulator pressure)					*4*[a]
Scram times (scram discharge volume high level-normal accumulator pressure)	*All*				
Scram times, rated power (normal accumulator pressure)					*4*[b]

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a. Value refers to the four slowest drives as determined from the normal accumulator pressure scram test at ambient reactor pressure.
b. Scram times of the four slowest rods consistent with the operating sequence will be determined at 25%, 50%, and 100% of rated power during planned reactor scrams at these power levels.
c. Establish initially that this check is normal operating procedure.

Criteria

Level 1 - Each CRD must have a normal withdraw speed ≤ 3.6 in./s, as indicated by a full 12-ft stroke in ≥ 40 s.

Upon scramming, the average of the insertion times of all operable control rods exclusive of circuit response times, must be no greater than:

Percent Inserted	*Insertion Time (s)*	
5	*0.375*	*Scram time is measured from time pilot scram valves solenoids are deenergized.*
20	*0.90*	
50	*2.0*	
90	*5.0*	

The average of the scram insertion times for the three fastest control rods in any group of four control rods in a two-by-two array shall be no greater than:

Percent Inserted	*Insertion Time (s)*	
5	*0.398*	*Scram time is measured from time pilot scram valves solenoids are deenergized.*
20	*0.954*	
50	*2.120*	
90	*5.300*	

Level 2 - With respect to the CRD friction tests, if the differential pressure variation exceeds 15 psid for a continuous drive in, a settling test must be performed in which case the differential settling pressure should not be < 30 psid nor should it vary by more than 10 psid over a full stroke. Lower differential pressures are indicative of excessive friction.

Each drive speed in either direction (insert or withdraw) must be 3.0 ± 0.6 in./s, indicated by a full 12-ft stroke in 40 to 60 s.

(6) SRM response and control rod sequence

Purpose

The purpose of this test is:

- *To achieve criticality in each specified sequence.*

- *To increase power in a safe and efficient manner and to demonstrate that the operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to the operator during startup.*

The effect of typical rod movements on reactor power will be demonstrated.

Description

The operational neutron sources will be installed prior to initial fuel loading. SRM count-rate data will be taken during rod withdrawals to critical and compared with stated criteria on signal count-to-noise ratio.

Two complementary control rod withdrawal sequences have been calculated which completely specify control rod withdrawals from the all-rods-in condition to the rated power configuration. Each sequence will be used to attain cold criticality. Rod patterns will be recorded periodically as the reactor is heated to rated temperature. As each rod group is completed during the power ascension, the electrical power, steam flow, and APRM response will be recorded.

A demonstration of the operability of the RWM may conveniently be made during this test.

Criteria

Satisfaction of the following criteria constitutes adequate source and SRM relationships.

Level 1 - There must be a neutron signal count-to-noise ratio of at least 2 to 1 on the required operable SRMs.

There must be a minimum count rate of three counts/s on the required operable SRMs.

(7) IRM performance

Purpose

To adjust the IRM system to obtain an optimum overlap with the SRM and APRM systems.

Description

The IRM system will initially be set at maximum gain prior to heatup. Adjustment of the IRMs will be made on the APRM-IRM power overlap region subsequent to calibration of the APRMs.

Criteria

Level 1 - Each IRM channel must be adjusted so that overlap with the SRMs and APRMs is assured.

The IRMs must produce a scram at 95% of full scale.

(8) <u>LPRM calibration</u>

<u>Purpose</u>

To calibrate the LPRM system.

<u>Description</u>

The LPRM channels will be calibrated to make the LPRM readings proportional to the average heat flux in the four corner fuel rods surrounding each chamber at the chamber elevation. The calibration factors are obtained from either an offline or process computer calculation.

<u>Criteria</u>

Level 1 - With the reactor in the rod pattern and at the power level at which the calibration is to be performed, the meter reading of each LPRM chamber will be proportional to the average heat flux in the four adjacent fuel rods at the height of the chamber.

(9) <u>APRM calibration</u>

<u>Purpose</u>

To present the method for calibrating the APRM channels.

<u>Description</u>

A heat balance will be made at least once each shift and after each major power level change. Each APRM channel reading will be adjusted to be consistent with the core thermal power as determined from the heat balance. During the initial heatup a preliminary calibration will be made by adjusting the APRM amplifier gains so that the APRM readings agree with a heat balance based on coolant temperature rise data. The first standard heat balance is made at the 25% power level.

<u>Criteria</u>

Level 1 - The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

(10) <u>Process computer</u>

<u>Purpose</u>

To verify the performance of the process computer under operating conditions.

<u>Description</u>

GE/PAC computer system program verifications and calculational program validations at static and at simulated dynamic input conditions will be preoperationally tested at the computer supplier's site and following delivery to the plant site. Following fuel loading, during plant heatup and the ascension to rated power, the NSSS and the balance-of-plant (BOP) system process variables sensed by the computer as digital or analog signals will become available. Verify that the computer is receiving correct values of sensed process variables and that the results of performance calculations of the NSSS and the BOP are correct. Verify proper operation of all computer functions during power operation.

<u>Criteria</u>

Level 2 - Program OD-1 and P-1 will be considered operational when:

- *The MCHFR calculated by an independent method and the process computer either:*
    - *Are in the same fuel assembly and do not differ in value by more than 10%.*
    - *If two different fuel assemblies are chosen by the two methods, the CHFR calculated by the other method in each assembly agrees with the MCHFR in that assembly by not more than 10%.*
- *When the LPRM calibration factors calculated by the independent method and the process computer agree to within 5%.*

The remaining programs will be considered operational upon successful completion of static testing.

(11) <u>RCIC system</u>

<u>Purpose</u>

To verify the operation of the RCIC system at operating reactor pressure conditions.

<u>Description</u>

Controlled and quick starts of the RCIC system will be done at reactor pressures near 150 psig and rated.

Verify proper operation of the RCIC system and determine time to reach rated flow. These tests may first be performed with the system in the test mode so that discharge flow will not be routed to the RPV. The final demonstration will be made so that discharge flow will be routed to the RPV while the reactor is at partial power.

Criteria

Level 1 - The RCIC system must have the capability to deliver rated flow, 400 gal/min, in less than or equal to the rated actuation time, 30 s, against rated reactor pressure.

(12) HPCI system

Purpose

To verify the proper operation of the HPCI system throughout the range of reactor pressure conditions.

Description

Controlled and quick starts of the HPCI system will be done at reactor pressures near 150 psig and at rated.

Verify proper operation of the HPCI system, determine time to reach rated flow, adjust flow controller in HPCI system for proper flowrate, and adjust overspeed trip of HPCI turbine.

These tests will be performed with the system in the test mode so that discharge flow will not be routed to the RPV. The final demonstration will be made so that discharge flow will be routed to the RPV while the reactor is at partial power.

Criteria

Level 1 - The time from actuating signal to required flow must be $<$25 s with reactor pressure between 150 psig and rated. With pump discharge pressure at $\leq$1220 psig the flow must be at least 4250 gal/min. The HPCI turbine must not trip off during startup.

(13) Selected process temperatures

Purpose

The purposes of this test are:

- *To establish the minimum reactor recirculation pump speed which will maintain water temperature in the bottom head of the reactor vessel within 145°F (80°C) of reactor coolant saturation temperature as determined by reactor pressure.*

- *To provide assurance that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations.*

Description

The applicable reactor parameters will be monitored while at hot standby conditions and after recirculation pump trips in order to determine that adequate mixing of the reactor water is occurring in *the lower plenum of the pressure vessel. The adequacy of the bottom drain line thermocouple as a means for measuring the bottom reactor vessel temperature will also be determined.*

Criteria

Level 1 - The reactor recirculation pump flow shall not be increased unless the coolant temperatures between the upper and lower regions of the reactor vessel are within 145°F (80°C).

Level 2 - The bottom head coolant temperature as measured by the bottom drain line thermocouple should be within 50°F (28°C) of reactor coolant saturation temperature.

(14) System expansion

Purpose

- *To verify that the reactor drywell piping system is free and unrestrained in regard to thermal expansion.*
- *To verify that suspension components are functioning in the specified manner.*
- *To provide data for calculation of stress levels in nozzles and weldments.*

Description

Observe and record the horizontal and vertical movements of major equipment and piping in the NSSS and auxiliary systems to assure components are free to move as designed. Adjust as necessary for freedom of movement.

Criteria

Level 1 - There shall be no evidence of blocking of the displacement of any system component caused by thermal expansion of the system.

Hangers shall not be bottomed out or have the spring fully stretched.

Level 2 - Final displacements of instrumented points shall not vary from the calculated values by more than ± 50% or ± 0.5 in., whichever is smaller. Displacements of < 0.25 in. shall be considered negligible since 50% of this value is contingent on the accuracy of measurements.

(15) Core power distribution

Purpose

- *To confirm the reproducibility of the TIP system readings.*
- *To determine the core power distribution in three dimensions.*

Description

A check of the reproducibility of the TIP traces is made twice; the first time the TIP system is used, and once again at a later date after the TIP system has been used a number of times and is broken in. The check is made with the plant at steady-state condition by producing several TIP traces in the same location with each TIP machine. The traces are evaluated to determine the extent of deviations between traces from the same TIP machine.

Core power distributions will be obtained at each major plateau during the power ascension program. Axial power traces will be obtained at each of the TIP locations, and this information will be used to determine the core power distribution using the process computer, an offsite computer or manual methods.

Criteria

Level 2 - In the TIP reproducibility test, the TIP traces should be reproducible within ± 3.0% relative error or ± 0.10-in. absolute error, taking into account the flux noise; i.e., this criterion is satisfied if either the ± 3.0% relative error or the 0.10-in. absolute error is satisfied.

(16) Core performance

Purpose

- *To evaluate the core performance parameters of the:*
  - *Core flowrate.*
  - *Core thermal power level.*
  - *Maximum fuel rod surface heat flux.*
  - *Core MCHFR.*
  - *Maximum average planar linear heat generation rate.*

Description

Core power level, maximum heat flux, core flowrate, hot channel coolant flow, MCHFR, fuel assembly power steam qualities, and maximum average planar linear heat generation rate will be determined at existing power levels. Plant and incore instrumentation, conventional heat balance techniques, and core performance worksheets and nomograms will be used. This will be performed above 10% power and at various pumping conditions and can be done independently of the process computer functions.

Criteria

Level 1 - Reactor power, maximum fuel surface heat flux, and MCHFR must satisfy the following limits:

Steady-state reactor power shall be limited to values on or below the licensed flow control line (maximum power of 2436 MWt with core flow of at least 78.5 x 10^6 lb/h).

Maximum fuel rod surface heat flux shall not exceed 135 W/cm^2 (429,350 Btu/h ft^2) during steady-state conditions when evaluated at the operating power level.

MCHFR shall not be < 1.9 when evaluated at rated power and flow. The basis for evaluation of MCHFR shall be Design Basis for Critical Heat Flux Condition in BWRs, APED-5286, September 1966.

(17) Steam production

Purpose

To demonstrate that the reactor steam production rate is satisfied.

Description

Operate continuously for 100 h at rated reactor conditions. When it is determined that all plant conditions are stabilized, the steam production rate will be measured during a 2-h period at appropriate steam conditions.

Criteria

Level 1 - The NSSS must produce 10,470,000 lb/h of steam of not <99.7% quality at a pressure of 985 psia at the second isolation valves, when operating at specified warranty conditions.

(18) Flux response to rods

Purpose

- *To demonstrate stability in the power-reactivity feedback loop with increasing reactor power.*

- *To determine the effect of control rod movement on reactor stability.*

Description

Additional movement tests will be made at chosen power levels to demonstrate that the transient response of the reactor to a reactivity perturbation is stable for the full range of reactor power. A centrally located rod will be moved, and the neutron flux signal from a nearby LPRM chamber will be measured and evaluated to determine the dynamic effects of rod movement.

Criteria

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to control rod movement.

Level 2 - The decay ratio is expected to be ≤ 0.25 for each process variable that exhibits oscillatory response to control rod movement when the plant is operating above the lower limit setting of the master flow controller.

(19) Pressure regulator

Purpose

- *To determine the reactor and pressure control system responses to pressure regulator setpoint changes.*
- *To demonstrate the stability of the reactivity-void feedback loop to pressure perturbations.*
- *To demonstrate the control characteristics of the bypass and control valves.*
- *To demonstrate the "takeover" capabilities of the backup pressure regulator.*
- *To optimize the pressure regulator settings to give the best combination of fast response and small overshoot.*

Description

The pressure setpoint will be decreased rapidly and then increased rapidly by ~ 10 psi and the response of the system will be measured in each case. The backup regulator will be tested by failing the operating pressure regulator and observing the backup regulator takeover control. The load reference setpoint will be reduced, and the test repeated with the bypass valve in control. The response of the system will be measured and evaluated and regulator settings will be optimized.

Criteria

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to pressure regulator changes.

Level 2 - In all tests except the simulated failure of the operating pressure regulator, the decay ratio is expected to be ≤ 0.25 for each process variable that exhibits oscillatory response to pressure regulator changes when the plant is operating above the lower limit setting of the master flow controller. During the simulated failure of the operating pressure regulator the backup regulator is expected to control the transient such that the reactor does not scram.

Steady-state hunting or limit cycles must be removed or reduced to a sufficiently small magnitude such that they are operationally acceptable.

(20) <u>Feedwater system</u>

<u>Purpose</u>

- *To demonstrate acceptable reactor water level control.*
- *To evaluate and adjust feedwater controls.*
- *To demonstrate capability of the automatic recirculation flow runback feature to prevent low water level scram following trip of one feedwater pump.*
- *To demonstrate adequate response to feed heater loss.*
- *To demonstrate general reactor pressure to inlet subcooling changes.*

<u>Description</u>

Reactor water level setpoint changes of ~ ± 6 in. will be used to evaluate and acceptably adjust the feedwater control system settings for all power and feedwater pump modes.

One of the two operating feedwater pumps will be tripped causing the automatic flow runback circuit to reduce power to within the capacity of the remaining pump. One feedwater heater will be bypassed and the resulting transients recorded.

<u>Criteria</u>

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to feedwater system changes.

Level 2 - The decay ratio is expected to be ≤ 0.25 for each process variable that exhibits oscillatory response to feedwater system setpoint changes when the plant is operating above the lower limit of the master flow controller. System response for large transients should not be unexplainably worse than preanalysis. The automatic flow runback feature will prevent a scram from low water level following a trip of one feedwater pump.

(21) <u>Bypass valves</u>

<u>Purpose</u>

- *To demonstrate the ability of the pressure regulator to minimize the reactor disturbance during an abrupt change in reactor steam flow.*
- *To demonstrate that a bypass valve can be tested for proper functioning at rated power without causing a high flux scram.*

Description

One of the turbine bypass valves will be tripped open by a test switch. The pressure transient will be measured and evaluated to aid in making final adjustments to the pressure regulator.

Criteria

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to bypass valve changes.

Level 2 - The decay ratio is expected to be ≤ 0.25 for each process variable that exhibits oscillatory response to bypass valve changes when the plant is operating above the lower limit setting of the master flow controller.

The maximum pressure decrease at the turbine inlet should be < 50 psig to avoid approaching low steam line pressure isolation or cause excessive water level swell in the reactor.

(22) Main steam isolation valve

Purpose

- *To functionally check the MSIVs for proper operation at selected power levels.*
- *To determine reactor transient behavior during and following simultaneous full closure of all MSIVs and following closure of one valve.*
- *To determine isolation valve closure time.*

Description

Functional check (10% closure) of each isolation valve will be performed at selected reactor power levels. A test of the simultaneous full closure of all MSIVs will be performed at ~ 100% of rated thermal power. Correct performance of the RCIC and relief valves will be shown. Reactor process variables will be monitored to determine the transient behavior of the system during and following full isolation. MSIV closure times will be determined. The maximum power conditions at which individual valve full closure tests can be performed without a reactor scram is to be established by such closure at selected power levels.

Criteria

Level 1 - MSIV closure time must be adjusted so that the time from initiation to the 90% closed indication will be < 4.5 s, and the time between 10% closed indication and the 90% closed indication will be > 2.8 s.

Level 2 - The maximum reactor pressure should be ~ 1200 psig, 40 psi below the first safety valve setpoint following closure of all valves. This is a margin of safety for safety valve weeping. During full *closure of individual valves, pressure must be 20 psi below scram, neutron flux must be 10% below scram, and steam flow in individual lines must be below the trip point.*

(23) Relief valves

Purpose

- *To verify the proper operation of the dual purpose relief safety valves.*
- *To determine their capacity.*
- *To verify their proper reseating following operation.*

Description

The main steam relief valves will each be opened manually so that at any time only one is open. Capacity of each relief valve will be determined by the amount the bypass or control valves close to maintain reactor pressure. Proper reseating of each relief valve will be verified by observation of temperatures in the relief valve discharge piping.

Criteria

Level 1 - Each relief valve must have a capacity of at least 810,000 lb/h at a pressure setting of 1143 psig.

Level 2 - Relief valve leakage must be low enough that the temperature measured by the thermocouples in the discharge side of the valves falls to within 10°F of the temperature recorded before the valve was opened.

(24) Turbine-generator - stop and control valve trips

Purpose

The purpose of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.

Description

The turbine stop valves will be tripped at selected reactor power levels and the main generator breaker will be tripped in such a way that a load imbalance trip occurs. Several reactor and turbine operating parameters will be monitored to evaluate the response of the bypass valves, relief valves, reactor protection system (RPS), and the effect of recirculation pump overspeed, if any, during the control valve trip. Additionally, the peak values and change rates of reactor steam pressure and heat flux will be determined. The ability to ride through a load rejection at 25% power without a scram will be demonstrated. A load rejection will be performed at 100% power (test condition 7).

Criteria

Level 1 - Reactor pressure shall be maintained below 1240 psig, the setpoint of the first safety valve, during the transient following fast closure of the turbine stop and control valves.

Reactor thermal power, as indicated by the simulated heat flux readout, must not exceed the safety limit line.

The turbine control valves must begin to close before the stop valves during the control valve trip.

Feedwater system settings must prevent flooding of the steam line following these transients.

Level 2 - The maximum reactor pressure should be < 1200 psig, 40 psi (2.8 kg/cm^2) below the first safety valve setpoint, during the transient following fast closure of the turbine stop and control valves. This pressure margin should prevent safety valve weeping.

The measurement of simulated heat flux must not be significantly greater than preanalysis.

The trip at 25% power must not cause a scram. The trip scram function for higher power levels must meet RPS specifications. The pressure regulator must regain control before a low pressure reactor isolation occurs.

Feedwater control adjustments shall prevent low-level initiation of the HPCI system and main steam isolation as long as feedwater flow remains available.

(25) Shutdown from outside the control room

Purpose

The purpose of this test is to demonstrate that the reactor can be brought from a normal initial steady-state power level to the point where cooldown is initiated and under control with RPV and water level controlled from outside the control room.

Description

The test will simulate the reactor shutdown following a control room evacuation. The reactor will be scrammed from a normal steady-state condition and the MSIVs will remain open. Following this event, the vessel water level and pressure will be controlled from outside the control room. All other operator actions not directly related to vessel water level and pressure will be performed in the MCR.

Criteria

Level 2 - During a simulated control room evacuation, the reactor must be brought to the point where cooldown is initiated and under control, and the reactor vessel pressure and water level are controlled using equipment and controls outside the control room.

(26) Flow control

Purpose

- *To determine the plant response to changes in recirculation flow and thereby adjust the local control loops.*

- *To examine the plant overall load following capability in order to establish correct interfacing of the pressure and flow control systems, including final settings for the master and local flow controllers*

Description

Various process variables will be recorded while step changes are introduced into the recirculation flow control system (increased and decreased) at chosen points on the 50%, 75%, and 100% load lines. Load following capability will be demonstrated in the automatic flow control mode.

Criteria

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to flow control changes.

Level 2 - The decay ratio is expected to be ≤ 0.25 for each process variable that exhibits oscillatory response to flow changes when the plant is operating above the lower limit setting of the master flow controller. Scram must not occur. Automatic flow control range must be at least 65% to 100% power along the full-power load line.

(27) Recirculation system

Purpose

- *To determine transient responses and steady-state conditions following recirculation pump trips at selected reactor power levels.*

- *To obtain jet pump performance data.*

- *To calibrate the jet pump flow instrumentation.*

Description

Single and both recirculation pumps will be tripped at various power levels.

One single pump trip at 50% power will be initiated by opening the generator field breaker. Two pump trips will be initiated by tripping the motor-generator (MG) set drive motors. Reactor pressure, steam and feedwater flow, jet pump delta P, and neutron flux will be recorded during the transient and at steady-state conditions. MCHFR evaluations will be made for conditions encountered during the *transient. The jet pump instrumentation will be calibrated to read total core flow, based on data obtained at the various test levels.*

Criteria

Level 1 - Transient MCHFR shall be > 1.0 at all times.

Level 2 - For each pump trip test, the minimum transient MCHFR based on operating data divided by the minimum transient MCHFR evaluated from design values is expected to be ≥ 1.0.

(28) Loss of turbine-generator and offsite power

Purpose

To demonstrate proper performance of the reactor and the plant electrical equipment and systems during the loss of auxiliary power transient.

Description

The loss of auxiliary power test will be performed at 25% of rated power. The proper response of reactor plant equipment, automatic switching equipment, and the proper sequencing of the diesel generator load will be checked. Appropriate reactor parameters will be recorded during the resultant transient.

Criteria

Level 1 - All test pressure transients must have maximum pressure values < 1240 psig which is the setpoint of the first safety valve. All safety systems, such as the RPS, the diesel generator, RCIC, and HPCI must function properly without manual assistance.

Level 2 - Normal reactor cooling systems should be able to maintain adequate torus water temperature, adequate drywell cooling, and prevent actuation of the automatic depressurization system. The maximum reactor pressure should be at least 40 psi below the first safety valve setpoint. This is a margin of safety for safety valve weeping.

(29) Recirculation MG set speed control

Purpose

- *To determine the individualized characteristics of the recirculation control system, i.e., drive motor, fluid coupler, generator, drive pump, and jet pumps.*
- *To obtain acceptable speed control system performance by the adjustment of linear and nonlinear controller elements.*

<u>Description</u>

During heatup small step changes will be made to the input of the scoop tube actuator. Tachometer output will be recorded to ascertain open loop response at several generator speeds.

When power level has been reached that will allow 100% pump speed, a gain curve will be taken of cam position, scoop tube position, and generator speed (tachometer voltage), all versus input current to the scoop tube actuator. These data will be used to set the span of the scoop tube actuator, the shape of the function generator curve, and the initial controller gain settings (proportional band and reset). Small speed demand changes will be made at the manual/auto stations over the entire speed range to demonstrate closed loop response and to give data for final controller gain settings.

<u>Criteria</u>

Level 1 - The decay ratio must be < 1.0 for each process variable that exhibits oscillatory response to recirculation MG set speed changes.

Level 2 - The decay ratio should be ≤ 0.25 for each process variable that exhibits oscillatory response to recirculation MG set speed changes over the entire range from 20% to 100% speed.

Final controller gains shall be those that give the fastest response within the above decay ratio criteria.

Following a 10% speed demand step from the low end of the speed control range, the time from the step demand until the generator speed peak occurs shall be > 10 but < 25 s.

Steady-state limit cycles (if any) shall cause turbine steam flow variations no larger than ± 0.5% of rated flow as measured by the gross generated electrical power.

(30) <u>Vibration measurements</u>

<u>Purpose</u>

- *To obtain vibration measurements on various reactor pressure vessel internals.*
- *To demonstrate the mechanical integrity of the reactor system under conditions of flow induced vibration.*
- *To check the validity and accuracy of the analytical vibration mode.*

<u>Description</u>

Vibratory responses will be recorded at various recirculation flowrates at temperatures <150°F (65.6°C) using strain gages on the fuel channels, accelerometers on the recirculation loops, and displacement gages on the shroud, steam separator, and jet pumps. Portable vibration sensor surveys will be made on the recirculation loops and differential pressure, and measurements will be made across the core plate, shroud head, and shroud wall. At hot, two-phase flow conditions, similar measurements will be made on the fuel channels, shroud, jet pump riser, and shroud head. The results of the vibration measurements *made at other boiling water reactor (BWR) installations will be considered in the final selection of components to be tested. Where possible, vibration measurements will be made as preoperational tests.*

Criteria

Level 1 - The criteria by which the results of the vibration tests will be judged involve complex, precalculated relationships among spatial locations, vibrational amplitudes, and vibrational frequencies as related to stress and limited by American Society of Mechanical Engineers Code, Section III. Because of their complexity, the criteria are not reproduced here.

(31) Main turbine stop valve surveillance test

Purpose

The purpose of this test is to demonstrate acceptable procedures for daily turbine stop valve surveillance tests at a power level as high as possible without producing reactor scram.

Description

Individual main turbine stop valves will be closed daily during plant operation and response of the reactor will be recorded. The maximum possible power level for this test along the rated rod pattern flow control line will be established. Each stop valve closure is manually initiated and reset. Rate of valve stroking and timing of the close-reopen sequence will be chosen to minimize the disturbance introduced.

Criteria

Level 2 - Peak neutron flux must be at least 5% below the scram trip setting. Peak vessel pressure must remain at least 10 psi below the high-pressure scram setting.

Peak steam flow in the high-flow lines must remain 10% below the high-flow isolation trip setting.

(32) Recirculation and jet pump instrumentation calibration

Purpose

The purpose of this test is to obtain a complete integrated calibration of the installed jet pump and recirculation pump flow instrumentation with the reactor shutdown prior to the jet pump flow calibration (test No. 27).

Description

A closely controlled pressure will be applied simultaneously to an entire loop of jet pump flow sensors to obtain an integrated calibration check of the system instrumentation. This procedure does not yield an actual calibration of the jet pump flow since this must be done during hot pressurized operation by comparison of the double- and single-tapped jet pump pressure drops as a function of the jet pump flow (test No. 27).

A similar procedure will be applied to the recirculation pump flow-nozzle pressure-drop instrumentation. The calibration of the recirculation pump pressure-drop instrumentation (total dynamic head) should be checked during the same testing period.

Criteria

None are applicable.

(33) Reactor water cleanup system

Purpose

The purpose of this test is to demonstrate the operability of the cleanup system under reactor operating temperature and pressure.

Description

With the reactor at rated temperature and pressure, a system isolation and restart will be performed to verify system capability. Data to determine heat exchanger capabilities with reactor at rated temperature and pressure will be obtained. The pump available net positive suction head (NPSH) will be determined during the hot standby operation mode defined by the system process diagram.

Criteria

Level 1 - Reactor water quality must be maintained according to the Technical Specifications.

Level 2 - The temperature at the tube side outlet of the nonregenerative heat exchangers shall not reach 140°F (60°C) in any cleanup system operating-mode. The pump available NPSH will be ≥ 1013 psia during the hot standby operation mode defined by the system process diagram.

(34) Residual heat removal (RHR) system

Purpose

To demonstrate the ability of the RHR system to remove residual and decay heat from the nuclear system so that refueling and nuclear servicing can be performed.

Description

During the first suitable reactor cooldown, the shutdown cooling mode of the RHR system will be demonstrated. The torus cooling mode will also be demonstrated, if necessary.

Criteria

Level 2 - The RHR system shall be capable of operating in the shutdown cooling mode (with both one and two heat exchangers) at the flowrates indicated on the process diagrams. (See Section 8 of Startup Test Instruction 71 for summary of flowrates.)

(35) Drywell atmosphere cooling system

Purpose

The purpose of this test is to verify the ability of the drywell atmosphere cooling system to maintain design conditions in the drywell during operating and post scram conditions.

Description

During heatup and power operation, data will be taken to ascertain that the drywell atmospheric conditions are within design limits.

Criteria

The drywell cooling system shall maintain drywell air temperatures and humidity at or below the specified design values.

(36) Cooling water systems

Purpose

The purpose of this test is to verify that the performance of the reactor building closed cooling water (RBCCW), turbine building closed cooling water, and service water systems are adequate with the reactor at rated temperature.

Description

With the reactor at rated pressure following initial heatup, data will be obtained to verify that the flowrates in the RBCCW and turbine building closed cooling water heat exchangers are adequate and properly balanced, and that the heat exchanger outlet temperatures are balanced within design values. Flowrate adjustments will be made as necessary to achieve satisfactory system performance. The test will be repeated at selected power levels to verify continued satisfactory performance with higher plant heat loads.

Criteria

Level 2 - Verification that the system performance meets cooling requirements as specified constitutes satisfactory completion of this test.

13.6.3 BOP STARTUP TEST RESTRICTIONS

Recommended procedures and limitations provided by the various equipment suppliers will be incorporated into detailed operating procedures prepared by plant personnel. In particular, procedures will be prepared and followed covering the normal startup and operation of the turbine-generator unit with its accessories and auxiliaries.

Restrictions will include limits on such items as vibration of rotating equipment, turbine temperature rate of rise and temperature differentials, generator and transformer temperature, minimum condenser vacuum, expansion rates and differentials, and feedwater purity.

TABLE 13.6-1

MAJOR PLANT TRANSIENTS

		Test Condition					
	Power (% rated)	25	50	75	65	100	75
	Core flow (% rated)	39	108	104	51	100	64
Test Title							
Feedwater pump trip				x		x	
MSIVs (one valve)			x	x			x
MSIVs (all valves)						x	
Turbine-generator stop valve fast close			x		x	x	
Turbine-generator control valve fast close		x					
Recirculation pump trip (one)			x	x		x	
Recirculation pump trip (two)			x	x		x	
Loss of generator and offsite power		x					

TABLE 13.6-2

STABILITY TESTS

	Test Condition								
Power (% rated)	25	32	50	48	75	37	65	100	50
Core Flow (% rated)	39	53	108	52	104	NC[a]	51	100	NC[a]
Test Title									
Flux response to rods	x	x	x	x	x	x	x	x	x
Pressure regulator setpoint	x	x	x	x	x	x	x	x	x
Pressure regulator backup regulator	x		x		x			x	
Feedwater system setpoint	x	x	x	x	x	x	x	x	x
Feedwater system drop heater								x	
Bypass valve	x	x	x	x	x		x	x	x
Flow control	x	x	x	x	x		x	x	

a. NC = Natural circulation.

TABLE 13.6-3 (SHEET 1 OF 3)

STARTUP AND POWER TEST PROGRAM

Test Condition (figure 13.6-1) Power (%)[a] Flow (%)[b]	Open Vessel or Cold Test	Heatup	20-30 ~39 a	50 % Load Line 45-55 ~108 b	22-32 NC	27-37 53 c	75% Load Line 70-80 ~104 d	43-53 52 e	32-42 NC f	100% Load Line 95-100 100 g	60-70 51 h	45-55 NC i	70-80 64 j	N-Cav k	Warranty
Chemical & radiochemical	x	x	x	x			x			x					
Radiation measurement	x	x	x	x			x			x					
Fuel loading	x														
Shutdown margin	x														
CRD	x	x	x	x						x	x				
SRM performance & control rod sequence	x	x	x			x		x			x				
Water level measurement		x				x				x					
IRM performance		x	x												
LPRM calibration			x[i]	x			x			x					
APRM calibration		x	x	x		x	x			x	x				
Process computer	x	x	x							x[m]					
RCIC		x	L												
HPCI		x		M											
Selected process temperature		x			x				x						
System expansion		x	x												
Core power distribution			x	x			x			x					
Core performance			x	x	x	x	x	x	x	x	x	x		x	x
Steam production															x
Flux response to rods			L	M		M	M	M	x	M	M	x			
Press reg:															
Setpoint changes			L	M		M	M	M	x	M	M	x			
Backup regulator			L	M			M			M					
Feedwater system:															
Feedwater pump trip							M			M					
Water level setpoint change			L	M		M	M	M	x	M	M	x			
Heater loss										M[g]					
Bypass valves			L	M		M	M	M	x	M	M	x			
MSIVs:															
Each valve		x		M, SP			M, SP						M, SP		
Full isolation										M, SE					
Relief valve:															
Capacity			L												
Actuation[c]		x[f]	L				M								
Turbine stop valve trip				M, SE[c]							A, SE				
and control valve trip			L, SP							M,SE,e, k					

TABLE 13.6-3 (SHEET 2 OF 3)

Test Condition (figure 13.6-1) Power (%)[a] Flow (%)[b]	Open Vessel or Cold Test	Heatup	20-30 ~39 a	50 % Load Line 45-55 ~108 b	50 % Load Line 22-32 NC	50 % Load Line 27-37 53 c	75% Load Line 70-80 ~104 d	75% Load Line 43-53 52 e	75% Load Line 32-42 NC f	100% Load Line 95-100 100 g	100% Load Line 60-70 51 h	100% Load Line 45-55 NC i	100% Load Line 70-80 64 j	N-Cav k	Warranty
Shutdown from outside control room			x												
Flow control			L[j]	M		M	M	M		M	M				
Recirc system:															
Trip each pump				M			M			M, 1					
Trip both pumps				M			M								
Flow calibration			x	x			x			x					
Non-cavit verification														x	
Loss of turbine-generator and offsite power				L, SE[c]											
Recirc MG set speed control		x		x											
Turbine stop valve surveillance test			L	M		M	M	M		M, SP[h]	M[h]		M, SP[h]		
Vibration measurements				x	x	x	x	x	x	x	x	x	x		
Recirc and jet pump inst calibration	x														
RWC system		x													
RHR system		x[i]	x[i]												
Off-gas system		x		x			x			x					
RHRSW		x[i]	x[i]												
Eq area cooling system		x		x[i]											
Drywell cooling		x	x	x			x			x					

LEGEND:

L - Local manual flow control mode
M - Master or local manual flow control mode (except flow control tests; must be in master manual)
A - Automatic flow control
X - Test independent of flow control mode
SP - Scram possibility
SE - Scram expected
NC - Natural circulation

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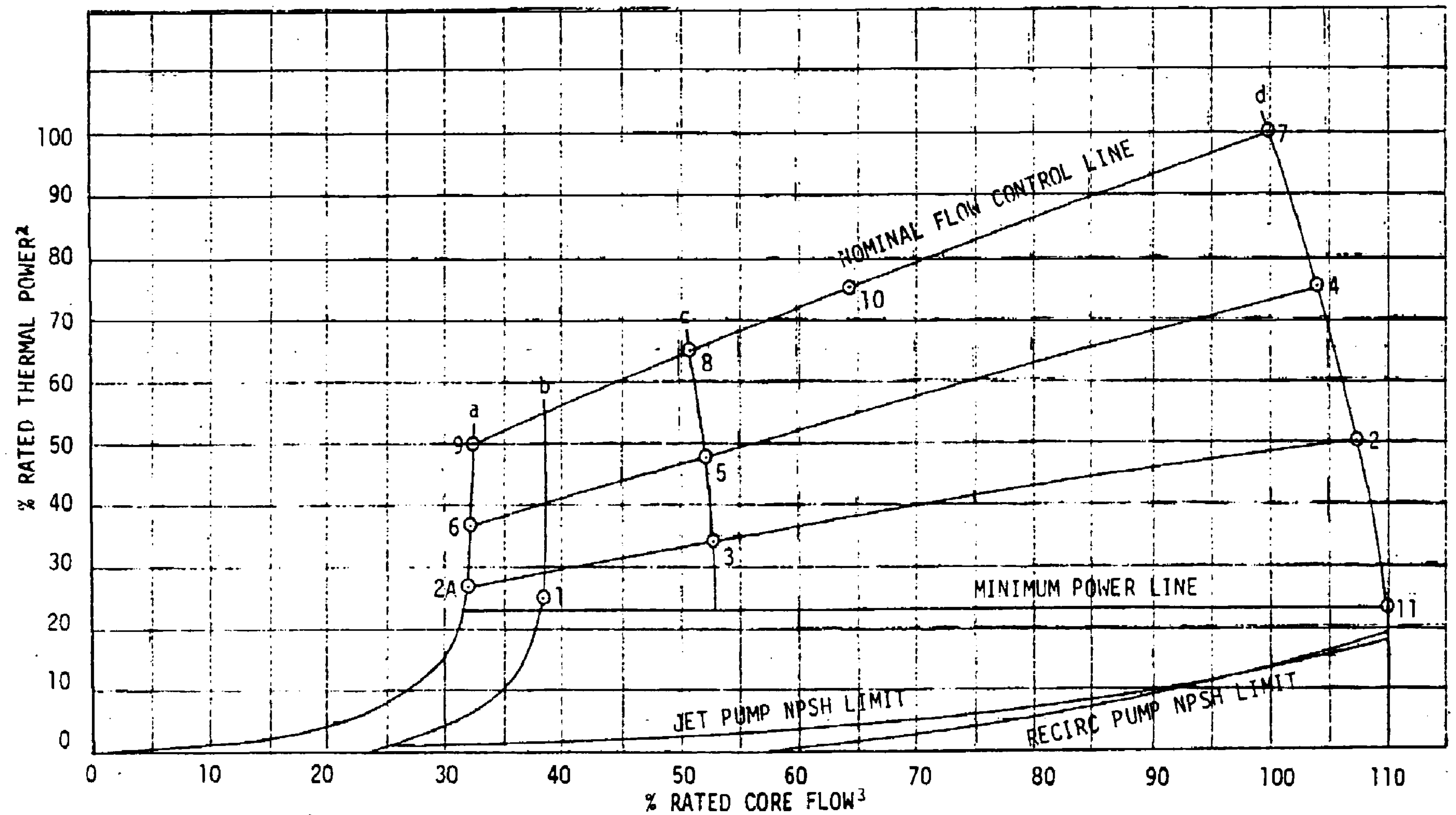
a. Percent of rated power = 2436 MWt.
b. Percent of rated flow = 78.5 x 10 lb/h.
c. Also obtain data with test 25, full isolation, and test 27.
d. Also obtain data with test 30, each and both recirculator pump trips. Trips of each recirculator pump at condition 4 of second pump at conditions 2 and 7, of both pumps at condition 2, and steady-state measurements at condition 2A are included only to meet vibration measurements program requirements.

TABLE 13.6-3 (SHEET 3 OF 3)

e. Perform test 5, timing of 4 slowest control rods in conjunction with these scrams.
f. Heatup tests of relief valves are to check operation only.
g. At 90% rated power.
h. Determine maximum power without scram.
i. These tests may be done any time during the test program and are not necessary to go to higher plateaus.
j. To be done during the 50% plateau testing but at test condition 1.
k. This test is a load rejection only.
l. Only on recirculation pump will be tripped.
m. DSTC should be performed here if not done at an earlier test condition.



TEST CONDITION NO.[1]	0	1	2	2A	3	4	5	6	7	8	9	10	11
ROD PATTERN	V	V	a	a*	a*	b	b*	b*	c	c*	c*	c*	V
%PUMP SPEED	0*	20	--	0*	--	--	--	0*	--	--	0*	--	--
%POWER	0	20-30	45-55	22-32	27-37	70-80	43-53	32-42	95-100	60-70	45-55	70-80	V
%CORE FLOW	0	~39	~108*	N.C.	53	~104*	52	N.C.	100*	51	N.C.	64	110*

1. See Table 13.6-3 for startup test titles.
2. Power in percent of rated thermal power, 2436 MWt.
3. Core flow in percent of rated core recirculation flow, 78.5 x 10^6 lbs/hr (35,700 MT/hr)

* Asterisked values are set as initial test conditions.

CONSTANT PUMP SEED LINES

a) Natural circulation.
b) 20% Pump Speed.
c) Contractual lower limit of master flow control.
d) Pump speed for full flow at full power.

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APPROXIMATE POWER FLOW MAP
SHOWING STARTUP TEST CONDITIONS

FIGURE 13.6-1

13.7 PLANT PROCEDURES

See HNP-2-FSAR section 13.5.

13.8 RECORDS

See HNP-2-FSAR section 13.6.

13.9 OPERATIONAL REVIEW AND AUDITS

See HNP-2-FSAR section 13.4.

13.10 (Deleted)

13.11 RADIOACTIVE MATERIAL SAFETY

The program for radioactive material safety is common to both HNP-1 and HNP-2. Refer to HNP-2-FSAR paragraph 12.5.3.7 for a discussion of radioactive material safety.

14.0 SAFETY ANALYSIS

See HNP-2-FSAR chapter 15, Safety Analysis.

APPENDIX A

PRESSURE INTEGRITY OF PIPING AND EQUIPMENT PRESSURE PARTS

A.1 SCOPE

This appendix provides additional information pertinent to the preceding sections concerning the pressure integrity of piping and equipment parts. Piping and equipment pressure parts are classified according to service and location. The design, inspection, and testing requirements which are defined for the equipment of each classification assure the proper pressure integrity.

The requirements and provisions of this appendix are applicable to piping and equipment pressure parts such as pipes, tubes, fittings, flanges, valve bodies, pump casings, and similar piping system parts which constitute a pressure boundary for the process fluid.

For the purposes of this appendix, the pressure boundary for the process fluid includes but is not necessarily limited to:

- Branch outlet nozzles or nipples.
- Instruments wells, reservoirs, flashpots, and the like.
- Pump casing and closures.
- Blind flanges and similar pressure closures.
- Studs, nuts, and fasteners in flanged joints between pressure parts.
- Bodies and pressure parts of inline components such as valves, traps, strainers, and the like.
- Instrument lines up to and including the first shutoff valve.

Specifically excluded from the scope of this appendix are:

- Nonpressure parts such as pump motors, shafts, seals, impellers, wear rings, valve stems, gland followers, seat rings, guides, yokes, operators, and similar trim.
- Any nonmetallic material such as packing, gaskets, fasteners (not in pressure part joints such as yoke studs, and gland follower studs).
- Washers of any kind.

Modifications made to the main steam relief valve discharge piping, the torus-attached piping, and their supports due to hydrodynamic loads identified during the Mark I Containment Long-Term Program are presented in supplement KA.

A.1.1 CODES AND SPECIFICATIONS

The piping and equipment pressure parts in this plant are designed, fabricated, inspected, and tested in accordance with recognized industrial codes and specifications as far as these codes and specifications can be applied. In some cases, these codes and specifications are used as the basis for design with supplementary requirements to increase safety and operational reliability. The application of the industrial codes and specifications is defined in this appendix as well as the application of those supplementary requirements which take precedence.

A.2 CLASSIFICATION OF PIPING AND EQUIPMENT PRESSURE PARTS

The classification scheme of piping systems important to safety is summarized on the system classification diagram (drawing no. H-16022). Table A.2-2 lists the codes for components and systems which comprise the reactor coolant pressure boundary (RCPB). Table A.2-3 lists the codes for other systems important to safety. Table A.2-4 explains the piping class designation used on piping and instrumentation diagrams for fluid systems important to safety. Table A.2-5 delineates the design transients for RCPBs and piping, and components.

For all piping and pressure equipment that is a part of the RCPB and other fluid systems important to safety, the acceptance codes are included in table A.2-2. Main steam isolation valves allowed the application of the ASME Code, summer 1969 addenda for acceptance criteria for liquid penetrant and magnetic particle examination. In this case, both General Electric's and the vendor's philosophy was to use the latest and best codes available.

Main steam piping, recirculation piping, and HPCI and RCIC steam piping used the acceptance standards of the USAS B31.7, 1969 Edition and addenda. The philosophy was to use the latest and best codes available. This variation is acceptable per 10 CFR 50.55a.

TABLE A.2-1

CLASS SCHEDULES

(Deleted)

TABLE A.2-2 (SHEET 1 OF 5)

CODES FOR COMPONENTS AND SYSTEMS WHICH COMPRISE THE REACTOR COOLANT PRESSURE BOUNDARY

The RCPB includes the reactor vessel and connecting pumps, pipes, and valves and extends to and includes the outermost primary containment isolation valves of the systems or components indicated. Those portions of the following systems or components which comprise the RCPB are shown as Class 1 on drawing no. H-16022. (They would be considered as Quality Group A in the classification system developed subsequent to the Hatch Nuclear Plant-Unit 1 (HNP-1) design.)

Reactor Vessel

The HNP-1 reactor pressure vessel (RPV) was designed in accordance with Section III of the 1965 edition and addenda through winter 1966 of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. The Code Cases used were 1332-2, 1335, 336, 1338-3, 1339-2, and 1359-1.

Control Rod Drive (CRD) Housing

The CRD housings were purchased and fabricated to the 1968 edition of the ASME Boiler and Pressure Vessel Code, Section III, including Code Case 1442 entitled, "Pressure Tests of Nuclear Components."

Main Steam Safety Relief Valves

Target rock model 0867F-001/09G-001 three-stage main steam safety/relief valves are designed and manufactured in accordance with ASME Boiler and Pressure Vessel Code Section III, Code Class A, 1968 Edition with Addenda through Winter 1970 as documented in drawing number S-63182.

Main Steam Isolation Valves (MSIVs)

The MSIVs were purchased in November 1969, requiring the use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-2, N-7, N-9, and N-10). In addition, the purchase specification requires conformance to ASME Code through winter 1968 addenda and applicable code cases. ASME, USAS B31.1.0 Codes and applicable code cases were used. No code case interpretations were used. Summer 1969 addenda were used for acceptance criteria for liquid penetrant and magnetic particle examination.

TABLE A.2-2 (SHEET 2 OF 5)

Main Steam Piping

The main steam piping was purchased in December 1969. This required the use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-7, N-9, and N-10). In addition, the purchase specification required conformance to ASME Codes through winter 1968 addenda and applicable code cases. This equipment was designed to USAS B31.1.0, but the acceptance standards of USAS B31I.7, 1969 edition with addenda were applied in lieu of the acceptance standards of American Standards Association (ASA) B31.1, Code Cases N-7, N-9, and N-10 per 10 CFR 50.55a. ASME Codes as stated above were also used. No code case interpretations were used.

Main Steam Flow Elements

The main steam flow elements were purchased in December 1969. This item required the use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-7, N-9, and N-10). In addition, the purchase specification required conformance to ASME Codes, 1968 edition through winter 1968 addenda and applicable code cases. ASME, USAS B31.1.0 Code Cases were used. No code case interpretations were used.

Recirculation Pumps

The recirculation pumps were purchased from Byron-Jackson Pump Division of Borg-Warner Corporation in November 1968. This equipment required the use of ASME Code for pumps and valves for nuclear power, 1968 edition including winter 1968 addenda and applicable code cases (the nondestructive examination and acceptance standards of Code Cases N-7, N-9, and N-10). ASME, 1968 edition as stated above was used. No code case interpretations were used. The pump cases were cast at the General Electric (GE) Foundary in Schenectady, New York, and were sent to Canadian GE Company, Ltd. in Scarborough, Ontario, Canada for weld repair and performance of the core closure welds.

A. All materials for this work were procured in the United States.

B. Canadian GE Company's previous experience includes fabrication of various components (pressure vessels, control codes, fuel-handling devices, etc.) for heavy-water reactors built in Canada.

C. The codes and standards applied to this work were the applicable United States codes and standards in effect at the time of purchase placement with Byron-Jackson of Los Angeles.

TABLE A.2-2 (SHEET 3 OF 5)

D. The quality assurance program followed during this work was the Byron-Jackson Pump Division program developed in response to GE's purchase specification, quality control plans, etc., as outlined in the purchase order for the pump. It was the responsibility of the Byron-Jackson Pump Division in Los Angeles to assure proper and complete implementation of the program. In addition, GE monitored Byron-Jackson's compliance with the program through all phases of fabrication.

Suction and Discharge Recirculation Valves

The 28-in. suction and discharge recirculation valves were purchased in February 1968. These required the use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-2, N-7, N-9, and N-10). In addition, the purchase specification required conformance to ASME Codes, 1965 edition through summer 1967 addenda and applicable code cases. ASME Codes and USAS B31.1.0 Codes as stated above were used. No code case interpretations were used.

Recirculation Piping

The recirculation piping was purchased in October 1969. It required the use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-7, N-9, and N-10). In addition, the purchase specification required conformance to ASME Codes through winter 1968, addenda and applicable code cases. This equipment was designed to USAS B31.1.0, but the acceptance standards of USAS B31.7, 1969 edition and addenda were applied in lieu of the acceptance standards of ASA B31 Code Cases N-7, N-9, N-10, per 10 CFR 50.55a. No code case interpretations were used.

The recirculation piping is analyzed to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1983 Edition with Winter 1984 Addenda, including the effects due to operation at 2804 MWt and reactor operating pressure increase to 1060 psia.

Recirculation Flow Elements

The recirculation flow elements were purchased in December 1969. These required to use of USAS B31.1.0, 1967 edition with addenda and applicable code cases (Code Cases N-7, N-9, and N-10). In addition, the purchase specification required conformance to ASME codes, 1968 edition through winter 1968 addenda and applicable code cases. ASME, USAS B31.1.0 Codes and applicable code cases were used.

TABLE A.2-2 (SHEET 4 OF 5)

High-Pressure Coolant Injection (HPCI) Turbine and Reactor Core Isolation Cooling (RCIC) Turbine Steam Piping

This piping was purchased in December 1969 and required the use of USAS B31.1.0, 1967 edition and applicable code cases. This piping was designed to B31.1.0, but the acceptance standards of USAS B31.7, 1969 edition and addenda were applied. B3l Code Case 74 was used for weld reinforcement limits.

Piping for Portions of the Following Systems Within the RCPB:

- Feedwater.
- Core spray (CS).
- Residual heat removal (RHR).
- Standby liquid control (SLC).
- Reactor water cleanup (RWC).
- CRD water return line.
- Instrument lines.
- Sample lines.

This piping was purchased in December 1969 and required the use of USAS B31.7 (Class 1), 1969 edition and applicable code cases. B31 Code Case 83 was used for weld reinforcement limits.

Valves 2 1/2 in. and Larger Other Than in Main Steam and Recirculation Piping

These valves were purchased in November 1969 and required the use of USAS B31.1.0, 1967 edition.

New and replacement valves for use in safety-related systems ordered after commercial operation have been purchased to ASME Section III. The appropriate nuclear class (1, 2, or 3) corresponds to the B31.7 class I, II, or III respectively. New and replacement valves for use in nonsafety-related systems ordered after commercial operation have been purchased to ANSI B31.1. Appropriate editions of and addenda to the above codes that were in effect at the time of material purchase were used for procurement.

TABLE A.2-2 (SHEET 5 OF 5)

Nondestructive examination for cast carbon steel valve castings was in accord with the Supplemental Requirements of American Society of Testing Materials (ASTM) A 216-68, Paragraph S-2 for all size valves and Paragraph S-3 for valves larger than 4 in.

Nondestructive examination for cast stainless steel valve castings was in accord with Supplemental Requirements of ASTM A 351-65, Paragraph S-4 for all valve sizes and Paragraph S-2 for valves larger than 4 in. in size.

Impact testing was performed on a selected basis in accord with Paragraph N.331.2, ASME Code, Section III, 1968 edition, winter 1969 addenda.

<u>Valves 2 in. and Smaller</u>

These valves were purchased on or after December 1970 and required the use of the draft ASME Nuclear Pump and Valve Code, 1968 edition, Class I, or other later applicable editions.

TABLE A.2-3 (SHEET 1 OF 8)

**CODES FOR OTHER SYSTEMS
IMPORTANT TO SAFETY**

Item	System or Component	Code	Comment
A.	CRD system	B31.7, Class	1
	Insert and withdraw lines		
	Scram discharge volume	B31.7, Class II	1
	Hydraulic control unit	See note.	8
B.	Standby Liquid Control System (SLCS)		
	Piping - storage tank to pumps	B31.7, Class III	3
	Piping - pumps to isolation valve	B31.7, Class II	2
	Pumps	See note.	9
	Storage tank	See note.	5
	Accumulator	See note.	6
	Valves 2 1/2 in. and larger	B31.1.0	10
	Valves 2 in. and smaller	NP&V, Class II	11
C.	Core Cooling Systems		
	RHR system		
	piping	B31.7, Class II	2
	pumps	ASME III, Class C	12
	heat exchangers		
	primary side	ASME III, Class C	14
	secondary side	ASME VIII	14
	CS System		
	piping	B31.7, Class II	2
	pumps	ASME III, Class C	12
	suction line from condensate storage tank	B31.7, Class III	3

TABLE A.2-3 (SHEET 2 OF 8)

Item	System or Component	Code	Comment
C. (cont)	HPCI and RCIC systems suction line from condensate storage	B31.7, Class III	3
	turbine steam supply and exhaust	B31.1.0	4
	suppression pool suction and pump discharge	B31.7, Class II	2
	pumps	ASME III, Class C	13
	turbines	See note.	7
	Valves in above systems		
	2 1/2 in. and larger	B31.1.0	10
	2 in. and smaller	NP&V, Class II	11
D.	Auxiliary Systems		
	RHR service water (RHRSW) system		
	piping	B31.1.0	15
	pumps	NP&V, Class III or ASME III, Class C	16 19
	valves	B31.1.0	10
	Plant service water system (to reactor bldg, control bldg, and diesel generator bldg)		
	piping	B31.1.0	15
	pumps	NP&V, Class III or ASME III, Class C	16 19
	butterfly valves	NP&V, Class III	17
	other valves	B31.1.0	18

TABLE A.2-3 (SHEET 3 OF 8)

COMMENT 1

This piping was purchased in May 1971 and required the use of American National Standards Institute (ANSI) B31.7, Class I, II, or III, 1969 edition and applicable code cases.

COMMENT 2

This piping was purchased in December 1969 and required the use of ANSI B31.7 (Class II), 1969 edition and applicable code cases. B31 Code Case 74 was used for weld reinforcement limits.

COMMENT 3

This piping was purchased in December 1969 and required the use of ANSI B31.7 (Class III), 1969 edition and applicable code cases. B31 Code Case 74 was used for weld reinforcement limits.

COMMENT 4

This piping was purchased in December 1969 and required the use of USAS B31.1.0, 1967 edition and applicable code cases. The piping was designed to USAS B31.1.0, but the acceptance standards of USAS B31.7, 1969 edition and addenda were applied. B31 Code Case 74 was used for weld reinforcement limits.

COMMENT 5 - Standby Liquid Control Tank

The SLC storage tank is designed, fabricated, inspected, and tested to meet the intent of American Petroleum Institute (API) Standard 650 and ASME Code, Section VIII, Division I.

All butt welds are given spot radiographic examination. Liquid penetrant inspection is conducted per ASME Code, Section VIII, Division I, on the following welds:

A. All tank nozzle welds below and including the overflow nozzle are examined internal and external to the tank.

B. All fillet and socket welds receive a random examination.

COMMENT 6 - SLC Accumulator

The design, construction, materials, inspection, and testing of the accumulator are in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, Division I. An ASME stamp is required. Other codes applied to the accumulator are:

- ANSI B16.11, Forged Steel Fittings, Socket Welded, and Threaded.

TABLE A.2-3 (SHEET 4 OF 8)

- AND Standard 10050 Bosses, Standard Dimensions for Gasket Seal Straight Thread.

COMMENT 7

The HPCI and RCIC turbines are categorized as machinery and thus do not fall within the classification groups as earlier identified. To assure that the turbine is fabricated to the standards commensurate with their performance requirements, GE has established specific design requirements for these components which are as follows:

- All welding qualified in accordance with Section IX, ASME Boiler and Pressure Vessel Code.
- All pressure containing castings and fabrications hydrotested to 1.5 x design pressure.
- All high-pressure castings are radiographed according.to the ASTM E-94, E-142, E-71, E-186, or E-280 (20% coverage, minimum severity level 3) .
- As cast surfaces, magnetic particle or liquid penetrant tested according to ASME Code, Section III, Paragraph N-323.3 or N-323.4.
- Wheel and shaft forgings ultrasonically tested according to ASTM A-388.
- Butt welds radiographed according to ASME Code, Section III, N-624, and magnetic particle or liquid penetrant tested according to ASME Code, Section III, N-626 or N-627.
- Notification made on major repairs, and records maintained thereof.
- Record system and traceability according to ASME Code, Section III, IX-225.
- Control and identification according to ASME Code, Section III, IX-226.
- Procedures conform to ASME Code, Section III, IX-300.
- Inspection personnel qualified according to ASME Code, Section III, IX-400.

COMMENT 8

The hydraulic control unit (HCU) is a GE factory assembled, engineered module of valves, tubing, piping, and stored water which controls a single CRD by the application of precisely

TABLE A.2-3 (SHEET 5 OF 8)

timed sequences of pressures and flows to accomplish slow insertion or withdrawal of the control rods for power control, and rapid insertion for reactor scram.

The sophisticated, highly engineered specialty components used in the HCU are the end result of extensive design evolution based on years of inservice experience and qualification testing. As the design of the HCU components evolved, it became apparent that the quality and reliability of production components could better be assured if GE assumed greater control of manufacture of components and their assembly into a hydraulic control system. Therefore, in 1965, a factory assembled HCU module was developed using the proven components from the older field-assembled hydraulic control system. Manufacturing tests on each unit include comprehensive functional hydraulic and electrical tests and a hydrostatic and pneumatic pressure test. A separate data sheet and test report is prepared for each unit produced. The required quality of purchase components and material is defined by purchase specifications and drawings, verified by written inspection procedures and assured in accordance with a quality control plan. The inplant material identification and control is facilitated because the HCU is a unique product in a factory producing a limited variety of reactor components, thus reducing the likelihood of substitution of incorrect material.

Although the HCU, as a unit, is field-installed and connected to process piping, many of its internal parts differ markedly from process piping components because of the more complex functions they must provide. Thus, although the codes and standards invoked by pressure integrity quality levels clearly apply at all levels to the interfaced between the HCU and the connecting conventional piping components--i.e., pipe nipples, fittings, simple hand valves, etc.; it is not clear that they similarly apply to the specialty parts; i.e., solenoid valves, pneumatic components, and instruments.

The design and construction specifications for the HCU do invoke such codes and standards as can be reasonably applied to individual parts in developing required quality levels, but these codes and standards are supplemented with additional requirements for these parts and for the remaining parts and details. For example:

- All welds are liquid penetrant inspected.
- All socket welds are inspected for gap between pipe and socket bottom.
- All welding is performed by qualified welders.
- All work is done per written procedures.

The following examples are typical of the problems associated with codes designed to control field-assembled components when applied to the design and production of factory fabricated specialty components:

TABLE A.2-3 (SHEET 6 OF 8)

A. The HCU nitrogen gas bottle is a spun forging which is mechanically joined to the accumulator. It stores the energy required to scram a drive at low vessel pressures. It has been code stamped since its introduction in 1966, although its size exempts it from mandatory stamping. It is constructed of a material listed by ASME Boiler and Pressure Vessel Code, Section VIII, which was selected for its strength and formability.

B. The scram accumulator is joined to the HCU by a split flange joint chosen for its compact design to facilitate both assembly and maintenance. Both the design and construction conform to the B31.1 piping code. This joint, which requires a design pressure of 1750 psig, has been proof tested to 10,000 psi.

C. The accumulator nitrogen shutoff valve is a 6000-psi cartridge valve whose copper alloy material is listed by ASME Boiler and Pressure Vessel Code, Section VIII. The valve was chosen for this service partly because it is qualified by the US Navy for submarine service.

D. The directional control valves are solenoid pilot-operated valves which are subplate mounted on the HCU. The valve has a body specially designed for the HCU, but the operating parts are identical to a commercial valve with a proven history of satisfactory service. The pressure containing parts are stainless steel alloys chosen for service, fabrication, and magnetic properties. The manufacturer cannot substitute a code material for that used for the solenoid core tube.

The foregoing examples are not meant to justify one pressure integrity quality level or another, but to demonstrate the codes and standards invoked by these quality levels are not strictly applicable to special equipment and part designs. Class 3 classification is generally applicable, supplemented by the QC techniques described above. Thus, the HCU is classified as Special Equipment.

<u>COMMENT 9</u>

The SLC pumps are built to the Reciprocating Pump Section of the Hydraulic Institute Standards. Welding and qualification testing was to USAS B31.1.0.

<u>COMMENT 10</u>

These valves were purchased in November 1969 and required the use of ANSI B31.1.0, 1967 edition.

Nondestructive examination for cast carbon steel valve castings was in accord with the Supplemental Requirements of ASTM A 216- 68, Paragraph S-2 for all size valves and Paragraph S-3 for valves larger than 4 in.

TABLE A.2-3 (SHEET 7 OF 8)

Nondestructive examination for stainless steel valve casting was in accord with Supplemental Requirements of ASTM A 351-65, Paragraph S-4 for all valve sizes and Paragraph S-2 for valves larger than 4 in. in size.

Impact testing was performed on a selected basis in accord with Paragraph N 331.2, ASME Code, Section III, 1968 edition, winter 1969 addenda.

COMMENT 11

These valves were purchased in December 1970 and required the use of the draft ASME Pump and Valve Code, 1968 edition, Class II.

COMMENT 12

The pressure boundary portions of these pumps were designed in accordance with ASME Code, Section III, Class C, 1968 edition including the spring 1969 addenda. These pumps were both fabricated and tested by Byron-Jackson Ltd., Division of Borg-Warner Corporation in Toronto, Ontario, Canada.

A. All materials with the exception of the minor attachment materials for the RHR pump, were procured from Canadian firms.

B. Byron-Jackson, Ltd. has fabricated the primary coolant pumps for every nuclear power plant in Canada (CANDU, PICKERING, and BRUCE) in addition to having fabricated numerous auxiliary and secondary pumps for nuclear applications.

C. The codes and standards applied to this work were the applicable United States codes and standards in effect at the time of purchase placement with Byron-Jackson of Los Angeles.

D. The quality assurance program followed during this work was the Byron-Jackson Pump Division program developed in response to GE's purchase specification, quality control plans, etc., as outlined in the purchase order for the pump. It was the responsibility of the Byron-Jackson Pump Division in Los Angeles to assure proper and complete implementation of the program. In addition, GE monitored Byron-Jackson's compliance with the program through all phases of fabrication.

COMMENT 13

The pressure boundary portions of these pumps were designed in accordance with ASME Code, Section III, Class C, 1968 edition including the winter 1968 addenda.

TABLE A.2-3 (SHEET 8 OF 8)

COMMENT 14

The RHR heat exchanger shell side was designed to ASME Code, Section III Class C, 1968 edition including the winter 1968 addenda and to Tubular Exchanger Manufacturers Association (TEMA) C. The tube side was designed to ASME Code, Section VIII, Division I, 1968 edition and winter 1968 addenda and to TEMA C.

COMMENT 15

This piping was purchased in December 1969 and required the use of USAS B31.1.0, 1967 edition and applicable code cases. For piping larger than 4 in. girth welds were 100% liquid penetrant tested. All longitudinal welds were 100% magnetic particle tested.

COMMENT 16

These pumps were purchased in July 1970 and required the use of ASME Nuclear Pump and Valve Code, Class III.

COMMENT 17

These valves were purchased in March 1971 and required the use of ASME Nuclear Pump and Valve Code, Class III.

COMMENT 18

These valves were purchased to the requirements of ANSI B31.1.0, 1967 edition.

COMMENT 19

Only the stainless steel bowl assemblies meet ASME III, Class C requirements.

TABLE A.2-4

PIPING CLASS DESIGNATIONS

Piping classes indicated on system piping and instrumentation diagrams are designated by a three letter code. The first letter indicates the primary valve and flange rating; the second letter indicates the type of material; the third letter indicates the code and code class to which the piping is designed and/or procured.

The designations are as follows:

First Letter

- D 900 (lb)
- E 600 (lb)
- F 400 (lb)
- G 300 (lb)
- H 150 (lb)
- J, K, L, M — For general use in identifying primary valve and flange rating.

Second Letter

- A Stainless steel
- B Carbon steel
- C, D, E, F, G, H, K, L, M — For general use in identifying special materials.

Third Letter

- A Nuclear Power Piping, USAS B31.7, Class I
- B Nuclear Power Piping, USAS B31.7, Class II
- C Nuclear Power Piping, USAS B31.7, Class III
- D Code for Pressure Piping, USAS B31.1.0, but acceptance standards of ANSI B31.7, 1969 edition and addenda were applied
- E Code for Pressure Piping, USAS B31.1.0
- F No code requirements

TABLE A.2-5 (SHEET 1 OF 7)

DESIGN TRANSIENTS

Reactor Vessel Transients

Stress and load analyses for reactor pressure vessel components are determined by the methods described in section 4.2.5.

Other Components

At the time procurement specifications were prepared the codes with which piping, pumps, and valves must comply did not require cyclic analysis. However, in order to further assure the integrity of pressure components within RCPB, thermal transients were specified for certain critical components and considerable cyclic analysis of the type specified in ANSI B31.7 was performed on the major piping.

Recirculation Valves

The following notes list the design transients which were specified:

A. General Requirements (Plant Operating)

All valves, except the pump suction valve, were considered exposed to the transients experienced by the discharge valve.

Unless stated otherwise, pressure in the pump suction valve was considered to be 25 psi above saturation pressure for the specified temperature during all of the following transients.

Add rated pump heat (specified in the specific plant data sheet or project sheet) to the pump suction valve pressure obtained from paragraph above, to obtain pressure in pump discharge valves during all plant operating transients.

In all cases, valves remain operable following the transients, and pressures integrity must be maintained.

B. Specific Requirements (Plant Operating)

Heatup and cooldown - All valves are designed to withstand 2000 cycles of heatup and cooldown within the temperature limits of 50°F and 575°F at a rate of 100°F/h.

Small temperature changes - All valves are designed to withstand 2000 changes of water temperature in steps of 29°F (either increase or decrease) at any temperature between the limits of 50°F and 575°F.

TABLE A.2-5 (SHEET 2 OF 7)

50°F temperature changes - All valves are designed to withstand 200 changes of water temperature in steps of 50°F (either increase or decrease) at any temperature between the limits of 50°F and 546°F.

Single safety or relief valve blowdowns - All valves are designed to withstand 30 cooling transients during which the water temperature changes from 546°F to 375°F in 10 min. (considered a step change in water temperature). Maximum pressure 3 s after start of the transient is 1200 psig in the pump suction valve.

Emergency conditions - The valves are designed to withstand two cooling transients in which the water temperature changes from 546°F to 281°F in 15 s (considered a step change in water temperature).

Improper start of pump in cold loop - All valves are designed to withstand a single heating transient caused by mistakenly starting the pump with the piping full of 100°F water and then drawing in 546°F water from the reactor vessel over a period of 15 s (considered to be a step increase in water temperature). Suction valve pressure remains constant at about 1025 psig.

Pressure transients - The following transients are primarily pressure disturbances. The temperature lags saturation conditions. To simplify design, consider temperature to be at the maximum design condition of 575°F during the following transients.

- *Turbine trip - All valves are designed to withstand 40 pressure transients from 1025 psig to 1150 psig in the pump suction valve. The pressure increase occurs during a period of 10 s and decreases to 955 psig in an additional 20 s.*

- *Reactor overpressure, delayed scram - All valves are designed to withstand a single pressure transient from 1025 psig to 1375 psig in the pump suction valve. The pressure increase occurs during a period of 2 s and decreases again to 1025 psig during a period of 30 s.*

C. Specific Requirements (Plant Shutdown)

Installed hydrotests, plant shutdown - All valves are designed to withstand the following installed hydrotests at 100°F with the pump stopped. (All valves are at the same pressure.)

- *130 cycles to 1275 psig.*

- *3 cycles to 1588 psig.*

TABLE A.2-5 (SHEET 3 OF 7)

Recirculation Pumps

The following notes list the design transients which were specified:

Cycle - An increase or decrease in temperature or pressure (or both) at a specified rate to a specified maximum or minimum and return at the same rate to the original conditions at a later time which is not necessarily specified. For instance, a reactor heatup at 100°F/h to operating conditions and cooldown several months later to the original startup conditions is considered as one cycle.

Transient - A change in only one direction at a specified rate. If the rate is different when changing in the other direction, it is classified as another transient.

Pressure integrity - No loss of system fluid or pressure through any leak path in the pump casing or cover and no failure of main cover bolting.

D. Design Criteria

Unless stated otherwise, the pumps are required to operate through the transients, and remain operable following the transients. In all cases, pressure integrity must be maintained.

Under conditions of relief or safety valve operation, the design pressure may be exceeded by no more than 10%.

The pump is designed to withstand the thermal effects as listed herein as well as the piping reactions and pressure effects.

Thermal transients - The pumps are considered to be at design pressure during all of the following thermal transients.

Heatup and cooldown - The pumps are designed to withstand 300 cycles of heatup and cooldown within the temperature limits of 50°F to design temperature at a rate of 100°F/h.

Small temperature changes - The pumps are designed to withstand 600-step water temperature changes of 29°F (either increase or decrease) at any temperature between the limits of 50°F and design temperature. These step changes may occur within 1 s. Changes do not occur more frequently than once per hour.

50°F temperature changes - The pumps are designed to withstand 200-step water temperature changes of 50°F (either increase or decrease) at any temperature between the limits of 50°F and design temperature. These step changes may occur within 3 s. Changes do not occur more frequently than once per hour.

TABLE A.2-5 (SHEET 4 OF 7)

Single safety or relief valve blowdowns - The pumps are designed to withstand 30 cooling transients as follows:

- *Pressure integrity evaluation - For purposes of evaluating pressure integrity, the water temperature is considered to change from 546°F to 375°F in 10 min at a constant rate.*

- *Pump operational capability evaluation - For purposes of evaluating possible pump operational problems, the water temperature is considered to change at a constant rate between temperatures as follows:*

  - *From 546°F to 500°F in the first 3 min.*

  - *From 500°F to 460°F in the next 7 min.*

  - *From 460°F to 395°F in the next 20 min and cools at a rate of 100°F/h thereafter.*

E. Emergency Conditions

The pumps are designed to maintain pressure integrity during two cooling transients, in which the water temperature changes from 546°F to 281°F in 15 s.

The pump pressure boundary remains suitable for service after the transient; however, it is not required that the pump remain operable. The seller states the expected consequences to the pump in the pump operation and maintenance manual.

Pump casing or cover must not leak during the transient. Mechanical shaft seal and gasket joint leakage is acceptable.

The casing must be suitable for putting back in service after dimensional checks and reworking without being cut out of the pipe line.

The rotating parts and cover may be repaired in the shop or replaced if necessary.

F. Improper Start of Pump in Cold Loop

The pump is designed to maintain pressure integrity during a single heating transient caused by mistakenly starting the pump with the piping full of 130°F water and then drawing in 546°F water from the reactor vessel over a period of 15 s.

The pump pressure boundary remains suitable for service after the transient; however, it is not required that the pump remain operable. The seller states the expected consequences to the pump in the pump operation and maintenance manual.

TABLE A.2-5 (SHEET 5 OF 7)

Pump casing or cover must not leak during the transient. Mechanical shaft seal and gasket joint leakage is acceptable.

The casing must be suitable for putting back in service after dimensional checks and reworking without being cut out of the pipe line.

The rotating parts and cover may be repaired in the shop or replaced if necessary.

G. Definition of Terms

Safety valve transient - The pumps are designed to withstand a single pressure transient to 110% of design pressure at design temperature during safety valve operation.

Installed hydrotests - The pumps are designed to withstand the following hydrotests at 100°F with the pump stopped.

- *130 cycles to 1300 psig.*
- *3 cycles to 1670 psig.*
- *If special precautions are necessary to protect pump seals, thrust bearings or other components during reactor vessel hydrotest, they are stated in the operation and maintenance manual.*

H. All Other Valves

At the time the procurement specifications for these components were prepared, USAS B16.5, the code with which these valves must comply, did not call for cyclic analysis. No thermal transients were specified for these valves.

Piping

The transients listed above under reactor vessel transients were considered in the analysis of piping within RCPB. All of the 2 in. and larger piping is analyzed for the effect of those transients in accordance with the B31.7 Code. The 1-in. and smaller piping was designed to the B31.1.0 Code but was purchased and installed to the B31.7 Code.

These 1 in. and smaller lines are analyzed for weight, thermal, and seismic stresses and are supported accordingly.

TABLE A.2-5 (SHEET 6 OF 7)

Main Steam

Flow induced vibrations have been measured on plants whose configuration is similar to that of HNP-1 and shown to be insignificant. For this reason, no additional measurements of flow induced vibrations in the main steam line piping for this plant is made.

The main steam piping is subjected to two transient conditions that produce dynamic loads acting on it. These two conditions are turbine stop valve closure and relief valve lifting. A conservative dynamic analysis is made for both of these transients to determine stress levels, rather than by actual test measurements. The analysis is performed on the SAP computer program, and a time-history of all the forces acting on the piping system during the transient is input. The methods for modeling the piping system, calculating the time-history of the transient loads, and determining the dynamic response of the piping system to these loads is shown to be conservative by comparison of the methods and procedures used in actual test data obtained from other plants. The moments from these loads are combined individually with earthquake by the square root of the sum of the squares method. These combined moments then are added to deadweight moments to determine bending stresses. The bending stresses plus the longitudinal pressure stresses are shown to be less than 1.2 S_h, in accordance with the principles and methods of ANSI B31.1.0.

Other Systems

The piping within other Seismic Category I systems which can be operated prior to startup is observed for vibration during preoperational testing of these systems. Valves and pumps are operated in such a way as to simulate to the extent practical and the conditions which apply when each system is called upon to provide its design function. Any observed displacement of piping which is judged to be significant is measured and the resultant stresses calculated. The resultant stresses are appropriately combined with the stresses caused by deadweight, earthquake, and pressure, and compared to the primary stress allowed by the appropriate code. If the code allowable stresses are exceeded, restraints are installed to eliminate the displacements or to reduce them to acceptable levels.

The displacements are measured by scratch gauges.

The transient conditions investigated are as follows:

A. *RHR system - When taking suction from the reactor, start the RHR pumps with the reactor injection valves open.*[(a)] *With the RHR pump running, close the reactor injection valves. Minimum flow bypass valves open automatically. Reopen reactor injection valves and stop RHR pumps.*

TABLE A.2-5 (SHEET 7 OF 7)

B. *CS system - When taking suction from the condensate storage tank, start the CS pumps with the reactor injection valves open.[(a)] With the CS pumps running, close the reactor injection valves. Minimum flow bypass valves open automatically. Reopen reactor injection valves and stop CS pumps.*

C. *HPCI system - When taking suction from the condensate storage tank, start the turbine-driven HPCI pump with the reactor injection valves open.[(a)] With the HPCI pump running, close the reactor injection valves. Minimum flow bypass valve open automatically. Reopen reactor injection valves and stop the HPCI pump.*

D. *RCIC system - When taking suction from the condensate storage tank, start the turbine-driven RCIC pump with the reactor injection valves open.[(a)] With the RCIC pump running, close the reactor injection valves. Minimum flow bypass valves will open automatically. Reopen reactor injection valves and stop the RCIC pump.*

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a. If necessary, the injection valves will be throttled to prevent the respective pump from operating past maximum runout flow.

A.3 DESIGN REQUIREMENTS

A.3.1 PIPING DESIGN

Pressure and temperature conditions to which piping pressure components are subjected are described in the appropriate system design section of the final safety analysis report (FSAR). All piping systems within the scope of this appendix including pipe, flanges, valves, and fitting meet the requirements of American National Standards Institute (ANSI) B31.1, or ANSI B31.7 as indicated in tables A.2-2 and A.2-3, including requirements for design, erection, supports, tests, inspection, and special additional supplementary requirements specified in this appendix.

Recirculation pipe meets the requirements of the ASME Boiler and Pressure Vessel Code, Section III.

All piping within the scope of this appendix was evaluated for the effects of operation at 2804 MWt and satisfies the applicable code requirements. A summary of the piping evaluation is provided in references 1, 2, 3, and 4.

A.3.1.1 Allowable Stresses

The allowable stress values of the applicable piping code are used. For materials not covered by the piping codes, the stress values of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are used.

A.3.1.2 Wall Thickness

Pipe wall thickness, fittings, and flange ratings are in accordance with the applicable code, including adequate allowances for corrosion and erosion according to individual system requirements.

A.3.1.3 Reactor Vessel Nozzle Load

All piping including instrument piping connecting to the reactor pressure vessel (RPV) nozzles is designed so that the nozzle to pipe interface load does not result in stresses in excess of the allowable material stresses. Thermal sleeves are used where nozzles are subjected to high thermal stresses.

A.3.1.4 Seismic Design

This section describes the criteria for determining the seismic adequacy of mechanical and electrical equipment including cable and conduit raceway systems. The criteria which are usually specified in general terms to include verification by tests or analyses remain valid and may continue to be used as determined appropriate. However, as an alternative, the methodology based on earthquake experience data developed by the Seismic Qualification Utility Group and documented in the Generic Implementation Procedure (GIP), Revision 2, plus any addition to the GIP reviewed and accepted by the Nuclear Regulatory Commission (NRC), for use in resolving Unresolved Safety Issue A-46, as required by NRC Generic Letter 87-02, may be used to verify the seismic adequacy of currently installed equipment after the equipment has been walked down and any outliers resolved, as well as new and replacement mechanical and electrical equipment within the GIP scope. However, this alternative method of verifying the seismic adequacy of equipment used for modifications and replacement equipment assemblies, subassemblies, and devices that are part of the assemblies is acceptable where no specific NRC commitment to use IEEE 344-1975 has been made.

For the purpose of seismic design, equipment and piping is categorized according to the following definitions:

Seismic Class 1

This class includes equipment and piping systems whose failure or malfunction could cause, or increase, the severity of the design basis accident (DBA), cause release of radioactivity in excess of 10 CFR 100 limits, or those essential for safe shutdown and immediate or long-term operation following a loss-of-coolant accident (LOCA).

Seismic Class 2

This class includes equipment and piping system whose failure would not result in the release of significant radioactivity and would not prevent reactor shutdown. The failure of Seismic Class 2 equipment and piping systems may interrupt power generation.

The equipment and piping considered as Seismic Class 1 are shown in table A.3-1. Seismic Class 1 equipment and piping systems are supported and restrained to meet the seismic design analysis criteria in compliance with applicable codes.

The dynamic analysis of Seismic Class 1 piping systems for seismic loads was performed using the spectrum response method, as applied to a lumped mass mathematical model of the piping systems. The maximum responses of each mode were calculated and combined by the square-root-of-the-sum-of-the-squares method to give the maximum response quantities resulting from all modes. The response thus obtained was combined with the results produced by other loading conditions to compute the resultant stresses. All modes having frequencies < 30 Hz are used. The percentage of critical damping used in the seismic analysis is defined in paragraph 12.3.3.2.1.2. The horizontal acceleration spectrum curves applied to the piping systems are developed as part of the seismic analysis for the building in which the piping is located.

A.3.1.5 Analysis of Piping

A.3.1.5.1 Primary Stresses (S_p)

Primary stresses are as follows:

A. Circumferential primary stress (S_R) - Circumferential primary stresses are below the allowable stress (S_h) at the design pressure and temperature.

B. Longitudinal primary stresses (S_L) - The following loads are considered as producing longitudinal primary stresses: internal or external pressures; weight loads including valves, insulation, fluids, and equipment hanger loads; static external loads and reactions; the inertia load portion of the seismic loads; and dynamic loads due to a rapid valve closure or opening.

When the seismic load is due to the OBE (maximum horizontal ground acceleration of 0.08 g), the vectorial combination of all longitudinal primary stresses (S_L) does not exceed 1.2 times the allowable stresses (S_h).

When the seismic load is due to the DBE (0.15-g horizontal), the vectorial combination of all longitudinal primary stresses generally does not exceed material yield stress at temperature. Specific cases where higher allowable limits are used for main steam piping are discussed in appendix C.

A.3.1.5.2 Secondary Stresses (S_E)

Secondary stresses are determined by use of the maximum shear stress theory:

$$T_{max} = \frac{1}{2}\sqrt{S_b^2 + 4S_t^2} = \frac{1}{2}S_E$$

therefore,

$$S_E = \sqrt{S_b^2 + 4S_t^2} \quad \text{(See ANSI B31.1.)}$$

The following loads are considered in determining longitudinal secondary stresses:

- Thermal expansion of piping.
- Movement of attachments due to thermal expansion.
- Forces applied by other piping systems as a result of their expansion.

- Any variation in pipe hanger loads resulting from expansion of the system.
- Anchor point movement portion of seismic loads.

The vectorial combination of longitudinal secondary stresses (S_E) does not exceed the allowable stress range (S_A), i.e., $S_E \leq S_A$, where:

$$S_A = f[1.25(S_c + S_h) - S_L]$$

(This is equation 1 from paragraph 102.3.2 of ANSI B31.1 modified to include the additional stress allowance permitted when $S_L < S_h$). The stress reduction factor, f, is based upon a time-limited aging analysis of the number of thermal cycles. The thermal cycles assumed for HNP are adequate to account for the period of extended operation during the renewed license term. (See HNP-2-FSAR sections 18.1 and 18.5.)

A.3.1.6 Special Requirements for Main Steam Piping

The main steam pipe supports and restraints are designed and constructed to assure that the second isolation valve functions, particularly in the event of a pipe failure downstream of the valve. All main steam pipe failure stops within the reactor building are designed to Seismic Class 1.

The main steam lines downstream of the second isolation valves are designed to ANSI B31.1 as a minimum with the use of Code Case 74, B31.1. In addition, the following requirements apply down to but not including the next valve, including all branch lines larger than 2 1/2-in. diameter:

A. Design and Analysis

   1. The design includes consideration of earthquake effects. Earthquake loading for the OBE (0.08-g horizontal acceleration) is treated as occasional load as provided for in ANSI B31.1, using suitable static loading corresponding to the pertinent terminal structure response spectrum.

   2. In order to determine the end displacements and seismic forces on the main steam piping, sufficient dynamic analyses have been performed to determine needed response spectra at the pipe terminal points.

B. Materials

   1. Seamless pipe is ASTM-A106 Grade B. Plate pipe is ASTM-A155 Class I, Grade KC 70.

   2. Certification in writing is required from the manufacturer that all pipe, fittings, flanges, bolting materials, valves, and welding wire meet applicable material specifications.

A. Fabrication and Erection

100% radiography is required on all butt welds.

A.3.1.7 Special Requirements for Emergency Core Cooling System (ECCS) Suction Piping

A. Short Run of Pipe

Each emergency core cooling subsystem suction line has a butterfly valve located as near to the pressure suppression chamber (torus) as practicable. These valves are located taking into account clearances required for the valve and operator. In all cases, these valves are located within 6 ft from the nozzle on the torus.

B. Design

The ECCS suction piping to the first valve is designed to the requirements of ASME, Section III, 1968 edition, Class B. This piping was furnished with and pressure tested as part of the primary containment vessel.

A.3.2 VALVE DESIGN

Valves are designed and rated by the manufacturer to meet the design pressure and temperature. They are in compliance with ANSI B16.5, "Steel Pipe Flanges and Flanged Fittings," Manufacturers Standardization Society, Standard Practice MSS-SP-66, "Pressure Temperature Ratings for Steel Butt Welded and End Valves," and the piping or valve codes indicated in tables A.2-2 and A.2-3.

A.3.3 PUMP DESIGN

The pressure retaining parts of pumps are designed to meet the design pressure and temperature in the piping to which they are attached. The codes specified for pumps are listed in tables A.2-2 and A.2-3.

A.3.4 SUPPORTS

The principal supports of the reactor coolant system components have been designed in accordance with the rules for design and materials in the power piping code ANSI B31.1 and the standard MSS-SP58. Supporting elements were designed in accordance with the criteria in table A.3-2.

The supports of the reactor coolant system components were evaluated for the effects due to operation at 2804 MWt and were shown to satisfy the applicable code requirements. A summary of the supports extended power uprate evaluations is presented in references 1, 2, 3, and 4.

REFERENCES

1. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDC-32749P, General Electric Company, July 1997.

2. "Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization," NEDC-33085P, GE Nuclear Energy, December 2002.

3. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

4. RER 03-254, Reactor Operating Pressure Increase from 1050 psia to 1060 psia, Engineering Evaluations.

TABLE A.3-1 (SHEET 1 OF 2)

SEISMIC CLASS 1 EQUIPMENT AND SYSTEMS

Reactor Assembly

- Fuel assembly
- Reactor vessel
- Reactor vessel support
- Reactor vessel stabilizer
- Shroud and shroud support, including core spray sparger
- Core spray line
- Core support
- Top guide
- Orificed fuel support
- Feedwater sparger
- Control rod including velocity limiter
- Control rod drive (CRD)
- CRD tube
- CRD housing
- CRD housing support
- Temporary control curtains
- Jet pump assembly
- Power range neutron detectors

Nuclear Boiler System

- Reactor vessel relief valves
- Reactor vessel safety valves
- Main steam piping out to the second isolation valves

Reactor Recirculation System

CRD System (Portions Necessary for Scram)

Standby Liquid Control System (Excluding Test Components)

Neutron Monitoring System

- Intermediate range monitor
- Average power range monitor including local power range monitor inputs

Reactor Protection System

Residual Heat Removal System

Core Spray System

High-Pressure Coolant Injection System

Reactor Core Isolation Cooling System

TABLE A.3-1 (SHEET 2 OF 2)

Primary Containment and Reactor Vessel Isolation Control System

Trip systems A and B
Isolation initiation channels

Incident Detection Circuitry

ECCS initiating channels and logic automatic depressurization system initiating channels and logic

Control Room Panels and Local Instrument Racks for Seismic Class 1 Systems

Piping Connections from the Reactor Vessel, Up to and Including the First Isolation Valve External to the Drywell

Isolation Valves

Residual Heat Removal Service Water System

Plant Service Water System (Parts which Serve Seismic Class 1 Equipment and All Piping in the Reactor Building)

Spent Fuel Storage Equipment

New Fuel Storage Equipment

Reactor Building Ventilation System (Isolation Valves and Controls)

Equipment Area Cooling Systems

Standby Gas Treatment System

Control Room Environmental System

Standby Electrical Power Systems

dc power system (125/250 V)
Standby ac power system
Emergency buses and other electrical gear to and including power equipment required for safe shutdown

Instrumentation and Controls Required for Operation of Seismic Class 1 Equipment and Systems

Plant Instrument Air System (Parts Required for Safe Shutdown)

Low-Low Set Relief Logic System

TABLE A.3-2

SUPPORTS

Component	Design Condition	Load Combinations	Primary Membrane Stress Intensity
Hangers, Guides, Snubbers, Anchors	Normal and upset	Weight + thermal expansion + OBE	S[a]
Hangers, Guides, Snubbers, Anchors	Emergency	Weight + thermal expansion + DBE[b]	.9 Sy[b]
Anchors	Faulted	Weight + thermal[c] expansion + DBE + blowdown due to pipe rupture	≤ Sy

a. S is the allowable stress for material under consideration as specified in ANSI B31.1 or SP58.
b. Sy is the yield strength of the material under consideration.
c. Certain pipe anchors and restraints are designed to secure the pipe against the loadings associated with pipe rupture in order to protect vital components such as containment penetrations.

A.4 MATERIALS

The material for piping and equipment pressure parts is in accordance with the applicable design code and the supplementary requirements and limitations specified herein. The materials used in valves or pumps which connect different classification in a piping system comply with the requirements of the highest classification.

A.4.1 BRITTLE FRACTURE CONTROL FOR FERRITIC STEELS FOR CLASS 1

The fracture or notch toughness properties and the operating temperature of ferritic materials in piping and pressure parts are controlled to ensure adequate toughness when the system is pressurized to more than 20% of the design pressure. Such assurance is provided by maintaining the lowest service metal temperature above the required minimum temperatures specified in Appendix G of the ASME Code Summer 1972 Addendum and in 10 CFR 50 Appendix G. The lowest service metal temperature is the lowest temperature which the metal experiences in service while the plant is in operation. It is established by appropriate calculations considering atmosphere ambient temperatures, the insulation or enclosures provided, and the minimum temperature maintained. Further interpretations and requirements are:

A. Charpy V Notch (American Society for Testing Materials (ASTM) Standard A-370 Type-A "Mechanical Testing for Steel Products") or dropweight (ASTM E208) tests were performed to demonstrate that all materials and weld metal meet brittle fracture requirements at test temperature. Test specimens were prepared and tested with minimum impact energy requirements in accordance with Table N-421 and the general provision of Paragraphs N-313, N-331, N-332, N-511 of Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code 1965 Edition Winter 1966 Addendum. The welding procedures used were qualified by impact testing of weld metal and heat-affected zone to the same requirements as the base metal in accordance with Paragraph N-541.

B. Impact tests were not required for the following:

   1. Bolting, including nuts, 1-in. nominal diameter or less.

   2. Bars with nominal cross-sectional area not exceeding 1 $in.^2$

   3. Materials with a nominal (section) wall thickness of < 1/2 in.

   4. Components including pumps, valves, piping, and fittings with a nominal inlet pipe size of 6-in. diameter and less, regardless of thickness.

   5. Consumable insert material, austenitic stainless steel, and nonferrous materials.

C. Impact testing was not required on components or equipment pressure parts having a minimum service temperature of 250°F or more when pressurized to over 20% of the design pressure.

   Example: Steam line was excluded from brittle fracture test requirement since the steam temperature is over 250°F when the steam line pressure is at the 20% design pressure.

D. Impact testing was not required on components or equipment pressure parts whose rupture could not result in a loss-of-coolant exceeding the capability of normal makeup systems to maintain adequate core cooling for the duration of a reactor shutdown and orderly cooldown.

E. These criteria apply to components and equipment pressure parts including flange bolts of the reactor coolant pressure boundary (RCPB) and do not apply to related components such as anchors, anchor bolts, hangers, suppressors, and restraints.

F. Hydrostatic test conditions need not be considered unless failure results in a condition requiring emergency core cooling.

The highest of the NDTT obtained from DWT tests, the highest of the temperatures corresponding to the 50 ft-lb value of the C fracture energy, and the lowest of the upper shelf C energy values for the "weak" direction (WR direction in plates) of the material could not be met at the time the final safety analysis report was issued without destructive examination of completed components.

A.4.2 BRITTLE FRACTURE CONTROL FOR FERRITIC STEELS FOR CLASSES 2 AND 3

The possibility of brittle fracture is considered in ferritic steel piping and equipment pressure parts of Classes 2 and 3 subjected to metal temperatures below 30°F during operating or testing. In cases where ferritic metal may be subjected to temperatures below 30°F, brittle fracture control is provided by material evaluation, design, fabrication, or inspection requirements selected to ensure adequate fracture toughness in the piping or components.

A.4.3 FURNACE SENSITIZED STAINLESS STEEL MATERIALS

Furnace sensitization of wrought austenitic stainless steel pressure boundary materials is avoided. Austenitic stainless steel is considered to be furnace sensitized if it has been heated by means other than welding within the range of 800°F to 1800°F, regardless of subsequent cooling rate. When heated above 1800°F the austenitic stainless steel is rapidly cooled through the range 1800°F to below 800°F to avoid sensitization. Furnace sensitized parts which are subsequently solution annealed are not considered to be sensitized. When furnace sensitization cannot be avoided, low carbon grade castings CF3 of CF3A of ASTM A351 and 308L filler metal is used. Use of other cast materials such as CF8, CF8A, CF8M, CF3M and 308, 309, 316, or 316L welding materials requires prior approval.

A.4.3.1 Stainless Steel Castings

Austenitic stainless steel castings contain a 5% minimum ferrite and are solution annealed at least once in the manufacturing process prior to final machining and after any major repair welding.

A.4.3.2 Stainless Steel Forgings

Austenitic stainless steel forgings are solution annealed at least once in the manufacturing process prior to final machining and after any major repair welding.

A.4.4 (Deleted)

A.4.5 SERVICE SENSITIVE PIPING

The RCPB system piping and fitting material, including weld material, has been reviewed to determine whether the guidelines of NUREG-0313, revision 2, have been met. See appendix H for current inservice inspection requirements.

A.5 **(Deleted)**

A.6 INSPECTION AND EXAMINATION

A.6.1 (Deleted)

A.6.2 INSPECTION AND EXAMINATION

Compliance with Inspection and Enforcement (IE) Bulletin 79-03A, Longitudinal Weld Defects in ASME SA-312 Type 304 Stainless Steel Pipe, is given in table A.6-1. See appendix H for current inservice inspection requirements.

TABLE A.6-1 (SHEET 1 OF 2)

IE BULLETIN 79-03A, "EVALUATION OF ASME SA-312 TYPE 304 SS SEAM WELDED PIPE"

Pipe Class	System Designation[a]	Pipe Size (in.)	Schedule	Nominal Wall Thickness (t_{nom}) (in.)	Minimum Wall Thickness (t_{min}) (in.)	Outside Diameter Do (in.)	Design Press (P) (psig)	Design Temp (T) (°F)	Calc Hoop Stress (S) (psi)	Allowable Stress (Sa) (psi)	Ratio S/Sa	Remarks
HAC	C 11	4	10S	0.120	0.105	4.50	25	150	526	17,600	0.03	No further action is required.[b]
HAC	C 41	3	10S	0.120	0.105	3.50	150	150	2440	17,600	0.14	
HAC	E 41	16	10S	0.250	0.219	16.00	125	100	4516	18,700	0.24	
HAC	E 41	10	10S	0.165	0.144	10.75	125	100	4616	18,700	0.25	
HAC	E 51	6	10S	0.134	0.117	6.625	125	100	3489	18,700	0.21	
HAC	P 11	16	10S	0.250	0.219	16.00	125	150	4516	17,600	0.26	
HAC	P 11	14	10S	0.250	0.219	14.00	125	150	3945	17,600	0.22	
HAC	P 11	10	10S	0.165	0.144	10.75	125	150	4616	17,600	0.26	
HAC	P 11	8	10S	0.148	0.130	8.625	125	150	4097	17,600	0.23	
HAC	P 11	6	10S	0.134	0.117	6.625	125	150	3489	17,600	0.20	
HAC	P 11	4	10S	0.120	0.105	4.50	125	150	2629	17,600	0.15	
HAB	2C 41	3	10S	0.120	0.105	3.5	150	150	2440	18,300	0.133	
HAB	2E 41	16	10S	0.250	0.219	16.00	125	100	4523	18,800	0.240	
HAB	2E 51	6	10S	0.134	0.117	6.625	125	150	3489	18,300	0.190	
HAB	2P 11	6	10S	0.134	0.117	6.625	25	150	698	18,300	0.038	
HAB	2P 11	16	10S	0.250	0.219	16.00	25	150	905	18,300	0.049	
HAC	2G 41	6	10S	0.134	0.117	6.625	150	150	4187	18,300	0.229	
HAC	2G 41	8	10S	0.148	0.130	8.625	150	150	4935	18,300	0.270	
HAC	2G 41	4	10S	0.120	0.105	4.50	150	150	3154	18,300	0.172	
HAC	2P 11	4	10S	0.120	0.105	4.50	25	150	526	18,300	0.029	
HAC	2P 11	14	10S	0.250	0.219	14.00	25	150	790	18,300	0.043	
HAC	2P 11	8	10S	0.148	0.130	8.625	25	150	823	18,300	0.045	
MEC	2G 11	1/2	40S	0.109	0.095	0.840	150	150	603	18,300	0.033	
MEC	2G 11	3/4	40S	0.113	0.099	1.050	150	150	736	18,300	0.042	
HAC	2P 11	14	10S	0.250	0.219	14.00	25	150	790	18,300	0.043	
HAC	2P 11	8	10S	0.148	0.130	8.625	25	150	823	18,300	0.045	
MEC	2G 11	1/2	40S	0.109	0.095	0.840	150	150	603	18,300	0.033	
MEC	2G 11	3/4	40S	0.113	0.099	1.050	150	150	736	18,300	0.042	
MEC	2G 11	3	10S	0.120	0.105	3.5	150	150	2440	18,300	0.133	
MEC	2G 11	2	40S	0.154	0.135	2.375	150	150	1260	18,300	0.069	
MEC	2G 11	6	10S	0.134	0.117	6.625	150	150	4187	18,300	0.229	

TABLE A.6-1 (SHEET 2 OF 2)

Pipe Class	System Designation[a]	Pipe Size (in.)	Schedule	Nominal Wall Thickness (t_{nom}) (in.)	Minimum Wall Thickness (t_{min}) (in.)	Outside Diameter Do (in.)	Design Press (P) (psig)	Design Temp (T) (°F)	Calc Hoop Stress (S) (psi)	Allowable Stress (Sa) (psi)	Ratio S/Sa	Remarks
MEC	2G 11	1	40S	0.133	0.116	1.315	150	150	790	18,300	0.043	
MEC	2G 11	4	10S	0.120	0.105	4.5	150	150	3154	18,300	0.172	
MEC	2G 11	1 1/2	40S	0.145	0.127	1.90	150	150	1062	18,300	0.058	
MEC	2G 11	3	10S	0.120	0.105	3.5	150	150	2440	18,300	0.133	
MEC	2G 11	2	40S	0.154	0.135	2.375	150	150	1260	18,300	0.069	
MEC	2G 11	1 1/2	40S	0.145	0.127	1.90	150	150	1062	18,300	0.058	
MEC	2G 11	2	40S	0.154	0.135	2.375	150	350	1260	16,400	0.077	
MEC	2G 11	3	10S	0.120	0.105	3.5	150	350	2440	16,400	0.149	
MEC	2G 11	1 1/2	40S	0.145	0.127	1.90	150	350	1062	16,400	0.065	
MEC	2G 11	1	40S	0.133	0.116	1.315	150	350	790	16,400	0.048	
MEC	2G 11	8	10S	0.148	0.130	8.625	150	350	4935	16,400	0.301	
MEC	2G 11	10	10S	0.165	0.144	10.750	150	350	5539	16,400	0.338	
MEC	2G 11	12	10S	0.180	0.158	12.750	150	350	6012	16,400	0.366	

a. MPL Code.

C11 - Control rod drive system
C41 - Standby liquid control system
E41 - High-pressure coolant injection system
E51 - Reactor core isolation cooling system
P11 - Condensate transfer and storage system

b. No further action is required for any of the pipe classes listed.

APPENDIX B

TECHNICAL SPECIFICATIONS

The HNP-1 Technical Specifications are contained in Appendices A and B of the Operating License.

APPENDIX C

NUCLEAR STEAM SUPPLY SYSTEM EQUIPMENT LOADING DESIGN

C.1 INTENT AND SCOPE

C.1.1 COMPONENTS DESIGNED BY RATIONAL STRESS ANALYSIS

These general design criteria are intended to apply to those ductile metallic structures or components which are normally designed using rational stress analysis techniques such as pressure vessels, reactor internal components, etc. The criteria may also be applied to those components or structures whose ultimate loading capability is determined by tests. These criteria are intended to supplement applicable industry design codes where necessary. Compliance with these criteria is intended to provide design safety margins which are appropriate to extremely reliable structural components when account is taken of rare event potentialities such as might be associated with a design basis earthquake (DBE) or primary pressure boundary coolant pipe rupture, or a combination of events.

C.1.2 COMPONENTS DESIGNED PRIMARILY BY EMPIRICAL METHODS

There are many important Seismic Class I components or equipment which are not normally designed or sized directly by stress analysis techniques. Simple stress analyses are sometimes used to augment the design of these components, but the primary design work does not depend upon detailed stress analysis. These components are usually designed by tests and empirical experience. Complete detailed stress analysis is currently not meaningful nor practical for these components. Examples of such components are valves, pumps, electrical equipment and mechanisms. Field experience and testing are used to support the design. Where the structural or mechanical integrity of components is essential to safety, the components referred to in these criteria must be designed to accommodate the events of the DBE or operating basis earthquake, or a design basis pipe rupture, or a combination where appropriate. The reliability requirements of such components cannot be quantitatively described in a general criterion because of the varied nature of each component and its specific function in the system.

C.2 LOADING CONDITIONS AND ALLOWABLE LIMITS

The loading conditions established herein are expressed in generic terms and are related in a probabilistic manner to the loads which are to be investigated for safety considerations. Related probabilistic definitions are used to determine an appropriate minimum safety factor which is used to establish structural design allowable limits and functional design allowable limits. Certain of the limits described in these criteria, i.e., deformation limit and fatigue limit, are included for completeness but do not necessarily require application to all components. Where it is clear to the designer that fatigue or excess deformation are not of concern for a particular structure or component, a formal analysis with respect to that limit is not required.

C.2.1 LOADING CONDITIONS

The loading conditions may be divided into four categories; normal, upset, emergency, and faulted conditions. These categories are generically described in the following paragraphs.

C.2.1.1 Normal Conditions

These are any conditions in the course of operation of the unit under planned and anticipated conditions, in the absence of upset, emergency, or faulted conditions.

C.2.1.2 Upset Conditions

These are any deviations from normal conditions anticipated to occur often enough that design should include a capability to withstand those conditions. The upset conditions include anticipated operational occurrences caused by a fault in a system component requiring its isolation from the system, transients due to loss of load or power, and any system upset not resulting in a forced outage. The upset conditions may include the effect of the operating basis earthquake (OBE).

C.2.1.3 Emergency Conditions

These are any deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity results as a concomitant effect of specific damage developed in the system.

C.2.1.4 Faulted Conditions

Faulted conditions are those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear system may be impaired to the extent where considerations of public health and safety are involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities. Among the faulted conditions may be a specified earthquake for which safe shutdown is required.

C.2.2 ALLOWABLE LIMITS

In addition to the generic definition of loading conditions in the preceding paragraphs, the meaning of these terms is expanded in quantitative probabilistic language. The purpose of this expansion is to clarify the classification of any hypothesized accident or sequence of loading events so that the appropriate limits or safety margins are applied. Knowledge of the event probability is necessary to establish meaningful and adequate safety factors for design. The following table illustrates the quantitative event classifications.

Loading Condition Probabilities

Upset (likely)	$1.0 > P_{40} \geq 10^{-1}$
Emergency (low probability)	$10^{-1} > P_{40} \geq 10^{-3}$
Faulted (extremely low probability)	$10^{-3} > P_{40} \geq 10^{-6}$

where:

P_{40} = 40-year event encounter probability

These probabilities have been assigned the appropriate structural design limits for the loading conditions in subsection C.2.1. A summary of these limits is shown in HNP-2-FSAR tables 4.2-1 through 4.2-4.

There are many places where, through the exercise of designer judgment, it is unnecessary to actually carry out a formal analysis for each of these limits. A simple example consists of the case where two pieces of pipe of different wall thicknesses are joined at a butt weld. If they are both subjected to the same loading, only the thinner piece would require a formal analysis to demonstrate that the primary stress limit has been satisfied.

The term SF_{min} is defined as the minimum safety factor on load or deflection and is related to the event probability by the following equation:

$$SF_{min} = \frac{9}{3 - \log_{10} P_{40}}$$

where:

$$10^{-1} > P_{40} \geq 10^{-5}$$

For event probabilities $< 10^{-5}$ or $> 10^{-1}$, the following apply:

Event Probability	Minimum Safety Factor
$10^{-5} > P_{40} \geq 10^{-6}$	1.125
$1.0 > P_{40} \geq 10^{-1}$	2.25

These expressions show the probabilistic significance of the classical safety factor concept as applied to reactor safety. The SF_{min} values corresponding to the event probabilities are summarized in table C.2-1.

The loadings which occur as a result of the conditions listed are factored into the design of the components in accordance with the requirements of the applicable design code, or to the requirements of these criteria. Where permitted by the applicable code and by these criteria, the SF_{min} may be progressively lowered to a minimum acceptable level on the basis that there is a lesser need for design margin for loading conditions which have a diminishing probability of occurrence.

Design stress limits which exceed the specified yield strength or which are equivalent to those associated with the faulted operating condition category (3 S_m for primary stress) are not used in the design of components of safety-related fluid systems outside the reactor coolant pressure boundary.

TABLE C.2-1

MINIMUM SAFETY FACTORS

Loading Conditions	Loads	P_{40}	SF_{min}
Upset	N and A_O	10^{-1}	2.25
	or		
	N and U	10^{-1}	2.25
Emergency	N and R	10^{-3}	1.5
	or		
	N and A_D	10^{-3}	1.5
	or		
	Other combinations in this probability range	$< 10^{-1}$ to 10^{-3}	< 2.25 to 1.5
Faulted	N and A_D and R	1.5×10^{-6}	1.125
	or		
	Other combinations in this probability range	$< 10^{-3}$ to 10^{-6}	< 1.5 to 1.125

where:

N = normal loads

U = upset loads (result in maximum system pressure) excluding earthquake

A_O = OBE

A_D = design basis earthquake

R = loads resulting from jet forces and pressure and temperature transients associated with rupture of a single pipe within the primary containment. This load is considered as indicated in the tables.

The minimum safety factor decreases as the even probability diminishes and if the event is too improbable (incredible: $P_{40} \leq 10^{-6}$), then no safety factor is appropriate or required.

C.3 METHOD OF ANALYSIS AND IMPLEMENTATION OF CRITERIA

The following evaluations were performed under the 10-PSI Dome Pressure Increase Project Report (GE-NE-0000-0003-0634-01, Revision 1, July 2003) by GE Nuclear Energy with the following conclusions:

Reactor Pressure Vessel (RPV) Fracture Toughness Evaluation

Since there is no change in thermal power with the reactor operating pressure increase (ROPI), there is no significant effect on the RPV fracture toughness evaluation performed for thermal power optimization (TPO).

RPV Stress Evaluation

The ROPI does not change the RPV conditions used for the external power uprate (EPU) and TPO evaluations. Hence, there is no impact.

RPV Internals Mechanical Evaluation

The reactor internal components have been evaluated for structural integrity due to load changes resulting from ROPI and it is concluded that the structural integrity of the reactor internal components is maintained within the allowable/design margins.

RPV Interval Pressure Differences

The results of the evaluations indicate that pressure differences across the RPV components remain within the design limits for ROPI.

C.3.1 REACTOR VESSEL

The reactor vessel has been designed, fabricated, inspected, and tested in accordance with the 1965 edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, its interpretations, and applicable requirements for Class A vessels as defined therein up to and including the winter 1966 addenda.

Stress analysis requirements and load combinations for the reactor vessel have been evaluated for the cyclic conditions expected throughout the plant life, with the conclusion that ASME Code limits are satisfied.

Appendix I contains the results of the detailed design stress analyses performed for the reactor vessel to meet the code requirements. Selected components, considered to have possibly higher than code design primary stresses as a result of rare events or a combination of rare events, have been analyzed in accordance with the requirements of the loading criteria in this appendix. Results of the most critical of those analyses are included in table C.3-1. The conclusion is that the limits in the criteria have been met.

C.3.1.1 Vessel Fatigue Analysis

An analysis of the reactor vessel shows that all components are adequate for cyclic operation by the rules of Section III of the ASME Code.

The critical components of the vessel are evaluated on a fatigue basis, calculating cumulative fatigue usage factors (CFUFs), which are ratios of required cycles to allowed cycles to failure for all operating cycle conditions. The CFUFs for the critical components of the vessel are below the ASME Code allowable of 1.0. The component cyclic or transient limit program (HNP-2-FSAR subsection 18.2.12) monitors four bounding locations on the reactor vessel to ensure the CFUFs do not exceed acceptance criteria.

C.3.1.2 Vessel Seismic Analysis

A seismic analysis was performed for a coupled system consisting of reactor building, drywell, reactor vessel and internals. The analysis is discussed in subsection C.3.2.3.

C.3.2 REACTOR VESSEL INTERNALS

The reactor vessel internals are designed using Section III of the ASME Boiler and Pressure Vessel Code as a guide. With the exception of the shroud repair hardware, the material used for fabrication of most of the internals is solution heat treated, unstabilized type 304 austenitic stainless steel conforming to American Society of Testing Materials (ASTM) specifications. Allowable stresses for the internals materials under normal operating conditions are taken directly from Section III. For the shroud repair hardware, Alloy X-750 component stresses are limited to 0.6 Sy for the total sustained tensile stress in in the normal operation condition only. This complies with the Alloy X-750 criterion of BWRVIP-84 but is more restrictive. The values of Sm and Sy of ASME Section III for Alloy X-750 material shall be as specified in Code Case N-60-5. In order to comply with the requirements of BWRVIP-84, fabrication and material requirements shall be in accordance with GE documents 26A5734, Reactor Internals Modifications Fabrication Specification and 26A5733, Reactor Internals Modifications Materials Requirements, respectively. For rare events or a combination of rare events, the internals have been analyzed in accordance with the requirements of the loading criteria in this appendix, and results of the most critical of those analyses are included in table C.3-1. The conclusion is that the limits in the criteria have been met.

C.3.2.1 Internals Deformation Analysis

C.3.2.1.1 Control Rod System

If there were excessive deformations of the control rod drive (CRD) system, made up of the CRD, CRD housing, control rod, control rod guide tube and fuel channels and the core structural elements which support them (top guide, core support and shroud and shroud support) they could possibly impede control rod insertion. The maximum loading condition that would tend to deform these long, slender components is the design basis earthquake (DBE). Analyses of the internal components which have the highest calculated stresses are included in a following section. The highest calculated stresses occur where the DBE and loads resulting from the design basis accident (DBA) line break are considered to occur simultaneously. Even in these cases, the primary stress levels are relatively low. No significant deformation is associated with these calculated stresses; therefore, rod insertion would not be impeded after an assumed simultaneous DBE and line break accident.

C.3.2.1.2 Core Support

The core support sustains the pressure drop across the fuel. This pressure drop is the only load which causes significant deflection of the core support. Excessive core support deflection could lift the control rod guide tubes off their seats on the CRD housings and thereby increase core bypass leakage. This upward deflection would have to be 1/2 in. to begin to lift guide tubes. The maximum deflections under normal operation conditions and pipe rupture differential pressures for the core support are calculated to be very small as compared to 1/2 in. The guide tubes, therefore, are not lifted off, although even if they were, this would not be of concern because bypass leakage at this time is not important.

C.3.2.2 Internals Fatigue Analysis

Fatigue analysis was performed using as a guide the ASME Boiler and Pressure Vessel Code, Section III. The method of analysis used to determine the cumulative fatigue usage is described in APED-5460, "Design and Performance of GE-BWR Jet Pumps," September 1968. The most significant fatigue loading occurs in the jet pump - shroud - shroud support area of the internals. The analysis was performed for Unit 1 of the Millstone Nuclear Power Station, a plant where the configuration (gusset-type shroud support) was almost identical to HNP-1. Therefore, the calculated fatigue usage is expected to be a reasonable approximation for this plant.

Loading combination and transients considered are:

- Normal startup and shutdown.
- OBE and DBE.
- Ten-min blowdown from a stuck relief valve.
- High-pressure coolant injection (HPCI) operation.
- Low-pressure coolant injection (LPCI) operation (DBA).
- Improper start of a recirculation loop.

Cumulative fatigue usage is:

$U_{allowable} = 1.0$

$U_{calculated} = 0.267$

The location of maximum fatigue usage is at the inside diameter (ID) of the jet pump diffuser adapter at the thin end of the tapered transition section.

C.3.2.3 Internals Seismic Analysis

The seismic loads on the reactor vessel and internals are based on a dynamic analysis of the coupled model consisting of reactor building, reactor vessel, and internals. The natural frequencies and mode shapes for the system were determined. The relative displacement, acceleration, and load response of the reactor vessel and internals were then determined using the response spectrum method of analysis. The dynamic responses were determined for each mode of interest and combined by square root of the sum of the squares of modal responses. The resulting values of displacements, accelerations, shears, and moments were used for design calculations. These results were combined with the results of other loads for the various loading conditions. The combined results for the critical components are presented in table C.3-1.

C.3.3 PIPING

C.3.3.1 Piping Flexibility Analysis

The piping was analyzed for the effects of dead loads, external loads, and thermal loads. Stresses calculated were combined bending and torsional stresses in accordance with American National Standards Institute B31.1, Power Piping, or later applicable standards where referenced. Intensification factors were applied in accordance with the referenced standards. Several pressure temperature cycles were evaluated, and the cycle representing the worst for thermal expansion stresses was selected for the design case. All critical points were evaluated to the stress limits of the above standards and, in addition, events with very low probability of occurrence were analyzed and stresses at all critical points compared with the limits defined in this load criteria. The load combination, allowable stresses, identification of points of highest stress, and highest stress values are summarized in tables C.3-1 and C.3-2.

C.3.3.2 Piping Seismic Analysis

The piping systems were dynamically analyzed using the response spectrum method of analysis. For each of the piping systems, a mathematical model consisting of lumped masses at discrete joints connected together by weightless elastic elements was constructed. Valves were also considered as lumped masses in the pipe, and valve operators as lumped masses acting through the operator center of gravity. Where practical, a support is located on the pipe at or near each valve. Stiffness matrix and mass matrix were generated, and natural periods of vibration and corresponding mode shapes were determined. Input to the dynamic analyses were the appropriately damped acceleration response spectra for the applicable floor elevation. The increased flexibility of the curved segments of the piping systems was also considered. The results for earthquakes acting in the X and Y (vertical) directions simultaneously and Z and Y directions simultaneously were computed separately. The maximum responses of each mode were calculated and combined by the square root of the sum of the squares method to give the maximum quantities resulting from all modes. The response thus obtained was combined with the results produced by other loading conditions to compute the resultant stresses.

C.3.3.3 Fatigue Monitoring of Reactor Coolant Pressure Boundary (RCPB) Piping

To account for the increase in operating life as a result of the renewed license, the CFUF for RCPB piping is monitored. Bounding locations in the feedwater, core spray, standby liquid control, HPCI, reactor core isolation cooling, reactor water cleanup, reactor vessel equalizer, RHR discharge piping outside the drywell, recirculation system drain lines, and main steam piping are monitored (HNP-2-FSAR subsection 18.2.12) to ensure the CFUF for this piping will not exceed 1.0 during the operation of the plant.

C.3.4 EQUIPMENT

The extent of stress analyses performed on equipment is dependent upon the type of equipment and the type of fabrication. Fabricated shapes are generally made from plate or rolled shapes with uniform thickness and shapes with regular geometric configurations. Cast shapes are generally made with nonuniform material thickness in complicated shapes that are not regular geometric configurations. Manufacturers have traditionally designed cast shapes conservatively since they do not lend themselves to rational analysis. Usually a design is developed based on extensive tests and experience. The equipment was analyzed to determine equipment adequacy for earthquake loading. The following equivalent static coefficients were used for the equipment listed in table C.3-1.

DBE

- Horizontal coefficient 1.50 g
- Vertical coefficient 0.14 g

OBE

- Horizontal coefficient 0.75 g
- Vertical coefficient 0.07 g

Class 1 equipment is qualified by test or analysis as discussed in paragraphs 12.3.3.2.1.17 and 12.3.3.2.1.10.

TABLE C.3-1 (SHEET 1 OF 20)

REACTOR VESSEL INTERNALS, ASSOCIATED EQUIPMENT AND PIPING

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Stabilizer Bracket and Adjacent Shell				
Primary stress limit - ASME Boiler and Pressure Vessel Code, Section III, defines membrane stress intensity limit for SA-533 - Grade B, C1.1.	Normal and upset condition load OBE Design pressure	Membrane	26,700	19,200
For normal and upset condition stress limit = 26,700 psi.	Emergency condition load DBE Design pressure	Membrane	40,000	24,100
For emergency condition stress limit = 1.5 x 26,700 = 40,000 psi. For faulted condition stress limit = 2.0 x 26,700 = 53,400 psi.	Faulted condition loads DBE Jet reaction force Design pressure	Membrane	53,400	26,300
Vessel Support Skirt				
Primary stress limit - ASME Boiler and Pressure Vessel Code, Section III, defines stress limit for SA-516 (70).	Normal and upset condition loads Deadweight OBE	Compressive membrane	12,000	9020
For normal and upset condition B = 12,000 psi.	Emergency condition loads Deadweight DBE	Compressive membrane	18,000	14,500
For emergency condition S_{limit} = 1.5 B = 18,000 psi. For faulted condition S_{limit} = 2.0 B = 24,000 psi.	Faulted condition loads DBE Jet reaction forces	Compressive membrane	24,000	14,900

TABLE C.3-1 (SHEET 2 OF 20)

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Shroud Support Gussets				
Primary stress limit - ASME Boiler and Pressure Vessel Code, Section III, defines allowable primary membrane stress plus bending stress for SB-168 material.	Normal and upset condition loads OBE Pressure drop across shroud (normal) Subtract deadweight	Membrane plus bending	34,950	31,300
For normal and upset condition $S_A = 1.5\ S_M = 1.5 \times 23.30 = 34.95$ ksi. For emergency condition $S_{limit} = 1.5\ S_A = 1.5 \times 34.95 = 52.43$ ksi.	Emergency condition loads DBE Pressure drop across shroud (normal) Subtract deadweight	Membrane plus bending	52,430	48,500
For faulted condition $A_{limit} = 2.0\ S_A = 2.0 \times 34.95 = 69.90$ ksi.	Faulted condition loads DBE Pressure drop across shroud during faulted condition Subtract deadweight	Membrane plus bending	69,900	64,300
Top Guide-Highest Stress Beam				
Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Section III, for type 304 stainless steel plate.	Normal and upset condition loads OBE Weight of structure	General membrane bending	25,388	22,530*
For normal and upset condition stress intensity $S_A = 1.5\ S_m = 1.5 \times 16,925$ psi $= 25,388$ psi.	Emergency condition loads DBE Weight of structure	General membrane plus bending	38,081	37,550*
For emergency condition $S_{limit} = 1.5\ S_A = 1.5 \times 25,388 = 38,081$ psi. For faulted condition $S_{limit} = 2\ S_A = 2 \times 24,388 = 50,775$ psi.	Faulted condition loads (same as emergency condition)	General membrane plus bending	50,775	37,550*

* Calculated stress results are updated in accordance with GE Hitachi Nuclear Energy Report 004N7114, “Hatch Unit 1 Top Guide Beam Connection Indication Structural Evaluation,” Revision 1, March 2018, to address indications found during refueling outage 1H28.

TABLE C.3-1 (SHEET 3 OF 20)

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Top Guide Beam End Connections				
Primary stress limit - ASME Boiler and Pressure Vessel Code, Section III, defines material stress limit for type 304 stainless steel.	Normal and upset condition loads OBE Weight of structure	Pure shear	10,155	7210*
For normal and upset condition stress intensity $S_A = 0.6\ S_m = 0.6 \times 16{,}925$ psi = 10,155 psi.	Emergency condition loads DBE Weight of structure	Pure shear	15,232	12,020*
For emergency condition S_{limit} 1.5 $S_A = 1.5 \times 10{,}555$ psi = 15,232 psi.	Faulted condition loads (same as emergency conditions)	Pure shear	20,310	12,020*
For faulted condition $S_{limit} = 2S_A = 2 \times 10{,}155$ psi = 20,310 psi.				

* Calculated stress results are updated in accordance with GE Hitachi Nuclear Energy Report 004N7114, “Hatch Unit 1 Top Guide Beam Connection Indication Structural Evaluation,” Revision 1, March 2018, to address indications found during refueling outage 1H28.

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Top Guide Aligners				
Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Section III. Inconel x 750.	Normal and upset condition loads OBE Weight of structure	General membrane plus bending	75,000	25,000
For normal and upset condition stress intensity $S_A = 1.5\ S_M = 1.5 \times 50{,}000$ psi = 75,000 psi.	Emergency condition loads DBE Weight of structure	General membrane plus bending	112,500	50,000
For emergency condition $S_{limit} = 1.5\ S_A = 1.5 \times 75{,}000$ = 112,500 psi.	Faulted condition loads (same as emergency conditions)	General membrane plus bending	150,000	50,000
For faulted condition $S_{limit} = 2\ S_A = 2 \times 75{,}000$ = 150,000 psi.				

TABLE C.3-1 (SHEET 4 OF 20)

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
Reactor Pressure Vessel (RPV) Stabilizer				
Primary stress limit - American Institute of Steel Construction (AISC) specification for the construction, fabrication, and erection of structural steel for buildings.	Upset condition Spring preload OBE	Rod	f_t = 127,000	f_t = 80,000[a]
		Bracket	f_b = 22,000	f_b = 17,000
	Emergency condition loads Spring preload DBE	Bracket	f_v = 14,000	f_v = 5,850
For normal and upset condition AISC allowable stresses, but without the usual increase for earthquake loads.			f_b = 33,000	f_b = 22,000
For emergency condition 1.5 x AISC allowable stresses.	Faulted condition Spring preload DBE Jet reaction load	Bracket	f_v = 21,000	f_v = 7,550
For faulted condition material yield strength.			f_b = 36,000	f_b = 23,800
			f_v = 21,500	f_v = 8,200
RPV Support (Ring Girder)				
Primary stress limit - AISC specification for the design, fabrication, and erection of structural steel for buildings.	Normal and upset condition Dead loads OBE Loads due to scram	Top flange	f_b = 27,000	f_b = 9700
		Bottom flange	f_b = 27,000	f_b = 12,000
		Vessel to girder bolts	f_t = 54,000	f_t = 18,000
For normal and upset condition 1.5 x AISC allowable stresses, but without the usual increase for earthquake loads.			f_v = 17,000	f_v = 5060
	Emergency condition Dead loads DBE	Top flange	f_b = 40,500	f_b = 30,900
		Bottom flange	f_b = 40,500	f_b = 24,000
For faulted condition 1.67 x AISC allowable stresses for structural steel members yield strength for high-strength bolts (vessel to ring girder).		Vessel to girder bolts	f_t = 91,000	f_t = 58,000
		Top flange	f_v = 30,000	f_v = 10,000
	Faulted condition Dead loads DBE Jet reaction load		f_b = 45,000	f_b = 38,000
		Bottom flange	f_b = 45,000	f_b = 27,400
		Vessel to girder bolts	f_t = 125,000	f_t = 72,500
			f_v = 72,000	f_v = 12,300

a. The ratio maximum stress/stress limit is highest for upset loading conditions.

TABLE C.3-1 (SHEET 5 OF 20)

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Core Support				
The allowable pressure is based on the following criteria:				
Buckling	Upset			
Normal/Upset = 0.40 (pc) Emergency = 0.60 (pc) where pc is the calculated buckling pressure.	Upset differential pressures	Buckling	29.0	27.9
	Emergency/Faulted			
	LOCA differential pressure	Sliding	36.8	29.5
Sliding				
Prevented within aligner capability				

TABLE C.3-1 (SHEET 6 OF 20)

Criteria	Loading	Primary Loading Type	Calculated Peak Value	Evaluation Basis
Fuel Assembly				
	Horizontal Direction:			
Channel primary stress limit (Note 1)	1. LOCA peak pressures	Channel differential pressure	16.7 psi	(Note 1)
	2. Safe shutdown earthquake	Horizontal acceleration profile	1.14 g	
Fuel assembly acceleration envelope (Note 1)	Vertical Direction:			
	1. LOCA peak pressures (Note 3)	Vertical accelerations	0.16 g (Note 2)	(Note 1)
	2. Safe shutdown earthquake			
	3. Scram			

Notes:

1. Acceptance criteria and evaluation basis are contained in NEDE 21175-3-P-A.
2. These values are determined using methodology contained in NEDE 21175-3-P-A. Fuel lift does not occur for HNP-1.
3. Which produce guide tube uplift forces.

TABLE C.3-1 (SHEET 7 OF 20)

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
CRD Housing				
Primary stress limit - The allowable primary membrane stress is based on the ASME Boiler and Pressure Vessel Code, Section III, for Class A vessels, for type 304 stainless steel. For normal and upset condition S_m = 15,800 psi @ 575°F.	Normal and upset condition loads Design pressure Stuck rod scram loads OBE	Maximum membrane stress intensity occurs at the tube-to-tube weld near the center of the housing for normal, upset, and emergency conditions.	15,800	14,480
For emergency condition S_{limit} = 1.5 S_m = 1.5 x 15,800 = 23,700 psi.	Emergency condition loads Design pressure Stuck rod scram loads DBE		23,700	22,030
CRD				
Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME Boiler and Pressure Vessel Code, Section III, for SA-212 TP316 tubing. For normal and upset condition S_A =1.5 S_m = 1.5 x 17,375 = 26,060 psi.	Normal and upset condition loads Maximum hydraulic pressure from the CRD supply pump. NOTE: Accident conditions do not increase this loading. Earthquake loads negligible	Maximum stress intensity occurs at a point on the Y-Y axis of the indicator tube.	26,060	20,790
Control Rod Guide Tubes				
Primary stress limit - The allowable primary membrane stress is based on the ASME Boiler and Pressure Vessel Code, Section III for Type 304 stainless steel tubing. For normal and upset condition S_d = 15,800 psi @ 575°F. For faulted condition S_{limit} = 2.0 S_d = 2.0 x 15,800 = 31,600 psi.	Faulted condition loads Deadweight (fuel) Pressure drop across guide tube due to jet pump flow Differential pressure due to steam line break DBE	The maximum stress under faulted loading conditions occurs at the center of the guide tube.	31,600	5365

TABLE C.3-1 (SHEET 8 OF 20)

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
Incore Housing				
Primary stress limit - The allowable primary membrane stress is based on the ASME Boiler and Pressure Vessel Code, Section III, for Class A vessels, for type 304 stainless steel.	Emergency condition loads Design pressure OBE	Maximum membrane stress intensity occurs at the outer surface of the vessel penetration	23,700	15,290
For normal and upset condition S_m = 15,800 psi @ 575°F.				
For emergency condition ($N + A_M$) S_{limit} = 1.5 S_m = 1.5 x 15,800 = 23,700 psi.				
CRD Housing Support				
Primary stress limit - AISC specification for the design, fabrication, and erection of structural steel for buildings.	Faulted condition loads Deadweight Impact force from failure of a CRD housing	Beams (top cord)	f_a = 33,000 f_b = 33,000	f_a = 11,800 f_b = 19,800
		Beams (bottom cord)	f_a = 33,000 f_b = 33,000	f_a = 9900 f_b = 13,800
For normal and upset condition F_a = 0.60 F_y (tension) F_b = 0.60 F_y (bending) F_v = 0.40 F_y (shear).	(Deadweights and earthquake loads are very small as compared to jet force.)	Grid structure	f_a = 41,500 f_b = 27,500	f_a = 40,000 f_b = 11,100
For faulted condition F_a limit = 1.5 F_a (tension) F_b limit 1.5 F_b (bending) F_v limit 1.5 F_y (shear) F_y = material yield strength.				

TABLE C.3-1 (SHEET 9 OF 20)

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
Recirculating Pipe And Pump Restraints				
Primary stress limit - Structural steel: AISC specification is for the design, fabrication, and erection of structural steel for buildings. For normal or upset condition $F_a = 0.60\ F_y$ (tension). For faulted condition F_a limit = 1.5 F_a (tension) F_y = yield strength cable (wire rope). For faulted condition $F_a = 0.80\ F_u$ (tension) F_u = ultimate strength.	Faulted condition loads Jet force from a complete circumferential failure (break) of recirculation line	Brackets on 28-in. pipe	33,000	29,000
		Cable on pump restraints	99,000	79,200
Hydraulic Control Unit Piping				
From USAS B31.1.0 - 1967 Code for power pressure piping. For normal condition S_h = 15,000 psi.	Normal condition load Maximum normal hydraulic system pump pressure	3/4-in. drive withdraw piping	15,000	14,526
For upset and emergency condition: When upset of emergency condition exists for < 1% of the time, the code allows 20% increase in stress. $S_a = 1.2\ S_h$ = 18,000 psi.	Upset condition load Shutoff pump pressure OBE (negligible load)	3/4-in. drive withdraw piping	18,000	16,950
	Emergency condition Shutoff pump pressure DBE (negligible load)	3/4-in. drive withdraw piping	18,000	16,950

TABLE C.3-1 (SHEET 10 OF 20)

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
Fuel Storage Racks				
New-fuel storage racks - Stresses due to upset, or emergency loading do not cause the racks to fail so as to result in a critical fuel array.	Emergency condition Dead loads Full fuel load in rack DBE	Column Base to column welds	16,000 11,000	2950[(a)] 1100[(a)]
Primary stress limit - Paper numbers 3341 and 3342, Proceedings of the ASCE, Journal of the Structural Division, December 1962 (task committee on lightweight alloys) (aluminum).		Channel Support channel to column weld	20,000 6000	3150[(a)] 2650[(a)]
Spent-fuel storage racks - Stresses due to normal, upset, or emergency loading do not cause the racks to fail so as to result in a critical fuel array.	Emergency condition A Dead loads Full fuel load in rack DBE	At column to base welds Support beam	11,000 35,000	1326[(a)] 33,500[(a)]
Primary stress limit - Paper numbers 3341 and 3342, Proceedings of the ASCE, Journal of the Structural Division, December 1962 (task committee on lightweight alloys) (aluminum).	Emergency Condition B (See below.)			
Emergency Condition Stress limit = yield strength at 0.2% offset.				

Emergency Condition B

Loading

In addition to the loading conditions given above, the racks were tested and analyzed to determine their capability to safely withstand the accidental, uncontrolled drop of the fuel grapple from its fully retracted position into the weakest portion of the rack.

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a. These values are calculated for a 1.5 g static seismic coefficient applied horizontally to the rack. Actual earthquake-induced loads give values much lower than these due to the structural stiffness. The load that was used to analyze the new-fuel and spent-fuel storage racks was derived from the seismic response curves with 2% damping (DBE). The DBE load for the fully loaded rack was considered to be the most critical and was not considered to be coincidental with any other load.

TABLE C.3-1 (SHEET 11 OF 20)

Fuel Storage Racks (continued)

Method of Analysis

The displacement of the vertical columns of the ends of the racks was determined by considering the effect of the grapple kinetic energy on the upper structure. The energy absorbed shearing the rack longitudinal structural member welds was determined. The effect of the remaining energy on the vertical columns was analyzed. Equivalent static load tests were made on the structure to assure that the criteria were met.

Results of Analysis

All criteria were met.

Analysis showed that the grapple would shear the welds in the area where the impact occurred. The longitudinal structural member bends but does not fail in shear. Grapple penetration into the rack is not sufficient to cause the vertical columns to deflect the fuel into a critical array. Static load testing showed that forces in excess of those resulting from a grapple drop are required to cause the columns to deflect to the extent that the criteria were violated.

TABLE C.3-1 (SHEET 12 OF 20)

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Main Steam Isolation Valves			
A. Body Minimum Wall Thickness Loads: Design pressure and temperature Primary membrane stress limit: S = 7000 lb/in.^{2} per ASA B 16.5	Minimum wall thickness in the cylindrical portions of the valve are calculated using the following formula: $t = 1.5\left[\frac{Pd}{2S - 1.2P}\right] + C$ where: S = allowable stress of 7000 psi P = primary service pressure, 655 psi d = inside diameter of valve port opening, in. C = corrosion allowance of 0.12 in.	t = 1.50 in.	Body wall thickness t > 1.75 in.
B. Cover Minimum Thickness Loads: Design pressure and temperature Design bolting load Gasket load Primary stress limit: Allowable working stress per ASME, Section VIII	$t = d\left[\frac{CP}{S} + \frac{1.78\,Wh_G}{Sd^3}\right]^{\frac{1}{2}} + C_1$ where: t = minimum thickness, in. d = diameter or short span, in. C = attachment factor P = design pressure, psi S = allowable stress, psi W = total, bolt load, lb h_G = gasket moment arm, in. C_1 = corrosion allowance, in.	t = 4.89 in.	Valves cover thickness and stress t = 5.719 in. S_{allow} = 17,500 lb/in.^{2}
C. Cover Flange Bolt Area Loads: Design pressure and temperature Gasket load Stem operational load Seismic load (DBE) Bolting stress limit: Allowable working stress per ASME Nuclear Pump and Valve Code Class 1	Total bolting loads and stresses are calculated in accordance with "Rules for Bolted Flange Connection," ASME Boiler and Pressure Vessel Code, Section VIII. Appendix II, except that the stem operational load and seismic loads are included in the total load carried by bolts. The horizontal and vertical seismic forces are applied at the mass center of the valve operator, assuming that the valve body is rigid and anchored.	S = 20,000 lb/in.^{2} @ 575°F	Flange bolt area and stress A_b = 53.04 in.^{2} S_b = 10,400 lb/in.^{2}

TABLE C.3-1 (SHEET 13 OF 20)

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Main Steam Isolation Valves (continued)			
D. Body Flange Thickness and Stress Loads: Design pressure and temperature Gasket load Stem operational load Seismic load (DBE) Flange stress limit: S_H, S_R, S_T 1.5 S_m per ASME Nuclear Pump and Valve Code, Class I	Flange thickness and stress are calculated in accordance with "Rules for Bolted Flange Connection," ASME Boiler and Pressure Vessel Code, Section VIII, Appendix II, except that steam operational load and seismic loads are included in the total load carried by the flange. The horizontal and vertical seismic forces are applied at the mass center of the valve operator assuming that the valve body is rigid and anchored.	S = 26,250 lb/in.^{2} S = 26,250 lb/in.^{2} S = 26,250 lb/in.^{2}	Body Flange thickness t = 4.25 in S_H = 17,641 lb/in.^{2} S_R = 12,147 lb/in.^{2} S_T = 7276 lb/in.^{2}
E. Valve Disc Thickness Loads: Design pressure and temperature Primary bending stress limit: Allowable working stress per ASME, Section VIII	Max. S_t = (See footnote a below.) where: W = pressure load, psi w = uniform load along inner edge, lb t = thickness of disc, in. a = outer radius of disc b = inner radius (fixed) of disc m = 3.33, reciprocal of Poisson's ratio	S = 17,500 lb/in.^{2}	Valve disc thickness and stress t = 5.625 in. S_t = 16,520 lb/in.^{2}
F. Valve Operator Supports Loads: Support rod stress limit: Allowable working stress per ASME, Section VIII	The valve assembly is analyzed assuming that the valve body is an anchored, rigid mass, and that the specified vertical and horizontal seismic forces are applied at the mass center of the operator assembly, simultaneously with operating pressure plus deadweight plus operational loads. Using these loads, stresses, and deflections are determined for the operator support components.	S = 20,000 lb/in.^{2}	Operator support stress and deflection Combined bending and tensile stress S = 10,125 lb/in.^{2} Deflection at operator S = 0.002 in.

a.

$$S_t = \left[\frac{3w}{4mt^2\left(a^2-b^2\right)}\right]\left[a^4(3m+1)+b^4(m-1)-4Ma^2b^2-4(m+1)a^2b^2\log\frac{a}{b}\right]+\frac{3W}{2\pi mt^2}\left[\frac{2a^2(m+1)}{a^2-b^2}\left[\log\frac{a}{b}+(m-1)\right]\right]$$

TABLE C.3-1 (SHEET 14 OF 20)

Topic

Main Steam Relief Valves

Target rock three-stage SRV model 0867F-001/09G-001 is qualified per drawings S-63182 and S-63848

TABLE C.3-1 (SHEET 15 OF 20)

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Recirculation Pumps			
A. Casing minimum wall thickness Loads: Normal and upset condition Design pressure and temperature. Primary membrane stress limit: Allowable working stress per ASME, Section III, Class C	$t = \frac{PR}{SE - 06P} + C$ where: t = minimum wall thickness, in. P = design pressure, psig. R = maxmum internal radius, in. S = allowable working stress, psi E = joint efficiency C = corrosion allowance, in.	2.75 in.	3.00 in.
B. Casing cover minimum thickness Loads: Normal and upset condition Design pressure and temperature. Primary bending stress limit: 1.5 S_m per ASME Code for Pumps and Valves for Nuclear Power Class I.	$S_r = \frac{3w}{4t^2}\left[a^2 - 2b^2 + \frac{b^4(m-1) - 4b^4(m+1)\ln\frac{a}{b} + a^2b^2(m+1)}{a^2(m-1) + b^2(m+1)}\right]$ $+ \frac{3W}{2\pi t^2}\left[1 - \frac{2mb^2 - 2b^2(m+1)\ln\frac{a}{b}}{a^2(m-1) + b^2(m+1)}\right]$	S_r = 14,950 psi S_t = 14,950 psi	S_r = 6140 psi S_t = 5243 psi

TABLE C.3-1 (SHEET 16 OF 20)

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Recirculation Pumps (continued)			
B. Casing cover minimum thickness (continued)	$S_t = \frac{3w\left(m^2 - 1\right)}{4mt^2}\left[\frac{a^4 - b^4 - 4a^2b^2 \ln\frac{a}{b}}{a^2(m-1) + b^2(m+1)}\right] + \frac{3W}{2\pi mt^2}\left[1 + \frac{ma^2(m-1) - mb^2(m+1) - 2\left(m^2 - 1\right)a^2 \ln\frac{a}{b}}{a^2(m-1) + b^2(m+1)}\right]$ where: S_r = radial stress at outer edge, psi. S_t = tangential stress at inner edge, psi. w = pressure load, psi. W = uniform load along inner edge, lb. t = disc thickness, in. m = reciprocal of poissons's ratio. a = radius of disc, in. b = radius of disc hole, in.		
C. Cover and Seal Flange Bolt Area Loads: normal and upset condition Design pressure and temperature Design gasket load Bolting stress limit: Allowable working stress per ASME, Section III, Class C	Bolting leads, areas, and stresses are calculated in accordance with "Rules for Bolted Flange Connections," ASME Section VIII, Appendix II.	Cover flange bolts 20,000 psi Seal flange bolts 20,000 psi	19,000 psi 17,750 psi

TABLE C.3-1 (SHEET 17 OF 20)

Criteria	Primary Loading	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Recirculation Pumps (continued)			
D. Cover Clamp Flange Thickness Loads: normal and upset condition Design pressure and temperature Design gasket load Design bolting load Tangential flange stress limit: Allowable working stress per ASME, Section III, Class C	Flange thickness and stress are calculated in accordance with "Rules for Bolted Flange Connections," ASME Section VIII, Appendix II.	Flange Thickness and Stress 7.25 in.	 8.25 in.

TABLE C.3-1 (SHEET 18 OF 20)

Criteria	Primary Loading	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness	
Recirculation Pumps (continued)				
F. Mounting Bracket Combined Stress Loads: Flooded weight DBE Combined stress limit: Yield stress	Bracket vertical loads are determined by summing the equipment and fluid weights and vertical seismic forces. Bracket horizontal loads are determined by applying the specified seismic force at mass center of pump-motor assembly (flooded). Horizontal and vertical loads are applied simultaneously to determine tensile, shear, and bending stresses in the brackets. Tensile, shear, and bending stresses are combined to determine maximum combined stresses.	Maximum Combined Stresses 15,600 psi	Bracket No. 1 16,180	No. 2 and 3 8955 psi
G. Stresses Due to Seismic Loads Loads: Operating pressure and temperature DBE Combined stress limit: Yield stress	The flooded pump-motor assembly is analyzed as a free body supported by constant support hangers from the pump brackets. Horizontal and vertical seismic forces are applied at mass center of assembly and equilibrium reactions are determined for the motor and pump brackets. Load, shear, and moment diagrams are constructed using live loads, dead loads, and calculated snubber reactions. Combined bending, tension, and shear stresses are determined for each major component of the assembly including motor, motor support barrel, bolting, and pump casing. The maximum combined tensile stress in the cover bolting is calculated using tensile stresses determined from loading diagram plus tensile stress from operating pressure.	Motor Bolt Tensile Stress 11,200 psi Pump Cover Bolt Tensile Stress 32,000 psi Motor Support Barrel Combined Stress 22,400 psi	 8161 psi 18,747 psi 1259 psi	

TABLE C.3-1 (SHEET 19 OF 20)

Criteria	Primary Loading	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Recirculation Valves			
A. Body Minimum Wall Loads: Design pressure and temperature Primary membrane stress limit: Allowable working stress per ASME, Section I	$t = \frac{1.5Pd}{2S - 2P(1-y)} + 0.1$ where: t = minimum wall thickness, in. P = design pressure, psig d = minimum diameter of flow passage but not < 90 % of inside diameter at welding end, in. S = allowable working stress, psi y = plastic stress dist. factor, 0.4	28-in. x 24-ft x 28-in. Valve Suction - t = 1.60 in. Discharge - t = 1.60 in.	 t = 1.75 in. t = 1.75 in.
B. Body-to-Bonnet Bolt Area Loads: Design pressure and temperature Gasket load Stem operational load Seismic load-MCE Bolting stress limit: Allowable working stress per ASME Nuclear Pump and Valve Code, Class I	Total bolting loads and stresses are calculated in accordance with "Rules for Bolted Flange Connections," ASME Boiler and Pressure Vessel Code, Section VIII, Appendix II, except that the stem operational load and seismic loads are included in the total load carried by bolts. The horizontal and vertical seismic forces are applied at the mass center of the valve operator assuming that the valve body is rigid and anchored.	Flange Bolt Area and Stress S_{allow} = 20,000 lb/in.^{2}	28-in. x 24-ft x 28-in. Valve Suction and Discharge A_b = 66.4 in.^{2} S_b = 17,567 in./in.^{2}

TABLE C.3-1 (SHEET 20 OF 20)

Criteria	Primary Loading	Allowable Stress or Minimum Thickness Required	Calculated Stress or Actual Thickness
Recirculation Valves (continued)			
C. Flange Thickness and Stress Loads: Design pressure and temperature Gasket load Stem operational load Seismic loads-MCE Flange stress limits: S_H, S_R, S_T: 1.5 S_m per ASME Nuclear Pump and Valve Code, Class I	Flange thickness and stress are calculated in accordance with "Rules for Bolted Flange Connections," ASME Boiler and Pressure Vessel Code, Section VIII, Appendix II, except that the stem operational load and seismic loads are included in the total load carried by the flange. The horizontal and vertical seismic forces are applied at the mass center of the valve operator assuming that the valve body is rigid.	28-in. Suction and Discharge S_H = 23,235 lb/in.^{2} S_R = 14,490 lb/in.^{2} S_T = 15,490 lb/in.^{2}	t = t 1/4 in. S_H = 19,223 lb/in.^{2} S_R = 4124 lb/in.^{2} S_T = 13,101 lb/in.^{2}
D. Valve Disc Thickness for 28 in. Valves Loads: Design pressure and temperature Primary bending stress limit: 1.5 S_m per ASME Nuclear Pump and Valve Code, Class I	$S_r = \frac{PR^2}{t^2}\left[1 - \frac{r^2}{R^2}\right]$ $S_t = \frac{0.306PR^2}{t^2}\left[(3+\nu) - (1+3\nu)\frac{r^2}{R^2}\right]$ where: S_r = radial stress, psi S_t = tangential stress, psi P = design pressure, psi r = radius to point of stress, in. t = thickness of disc, in. ν = Poisson's ratio, 0.27	28-in. x 24-ft x 28-in. Suction and Discharge S_{allow} = 21,350 lb/in.^{2}	t = 30 in. S_t = 14,712 lb/in.^{2} S_r = 12,328 lb/in.^{2}

TABLE C.3-2 (SHEET 1 OF 2)

MAIN STEAM LINE PIPING SYSTEM (CLASS 1 PIPE)

Condition	Load Combination	Criteria
Design	P + W + OBE	Eq 9A $< 1.5\ S_m$
Normal and Upset	For the dynamic loads, individually considering: OBE, TSV, RV with other ASME Section III Code-defined loads	Eq 9B $< 1.8\ S_m$ Eq 10 $< 3.0\ S_m$ Eq 12 $< 3.0\ S_m$ Eq 13 $< 3.0\ S_m$ Eq 14 U $< 1.0\ S_m$
Emergency	$P_e + W + [(OBE)^2 + (RV)^2]^{1/2}$	Eq 9C $< 2.25\ S_m$
	$P_e + W + [(OBE)^2 + (TSV)^2]^{1/2}$	
Faulted	$P_e + W + [(DBE)^2 + (TSV)^2]^{1/2}$	Eq 9D $< 3.0\ S_m$
	$P_e + W + [(DBE)^2 + (RV)^2]^{1/2}$	

LEGEND

P = stresses due to design pressure.
P_e = stresses due to peak pressure.
W = stresses due to weight pressure.
RV = stresses due to safety relief valve opening.
TSV = stresses due to turbine stop valve closure.

TABLE C.3-2 (SHEET 2 OF 2)

Criteria Per ASME Section III NB-3600		Node No.	Main Steam Line	Maximum Stress Intensities (psi) Power Uprate Stress	Code Allowable Stress	Ratio: Power Uprate to Allowable[a]
Equation 9:	Design	530	B	14,927	26,550	0.56
	Normal/Upset	250	B	23,247	31,860	0.73
	Emergency	300	C	21,485	39,825	0.54
	Faulted	250	B	28,088	53,100	0.53
Equation 10		531N	RCIC	71,493	53,100	1.35[a]
Equation 12		531N	RCIC	49,479	53,100	0.93[b]
Equation 13		75F	B	35,556	53,100	0.67
Equation 14 (Fatigue)		530	D	CUF = 0.64	CUF < 1.0	

a. Since equation 10 is not satisfied, the piping is qualified by meeting equations 12 and 13.
b. Stress indices for node points 531N were calculated using ASME Code Section III, Table NB-3685.1-2.

D.1 (Deleted)

D.2 (Deleted)

D.3 (Deleted)

D.4 (Deleted)

D.5 (Deleted)

D.6 (Deleted)

D.7 (Deleted)

D.8 (Deleted)

D.9 QUALITY ASSURANCE PROGRAM - OPERATIONS

The operations Quality Assurance (QA) Program for Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1) is the same as that for other SNC-operated plants. However, minor administrative and operational differences caused by differences in design limits and different standard and code commitments may exist. The operations quality assurance program is described in the SNC Quality Assurance Topical Report (QATR).

The items covered under the QA Program are the safety-related structures, systems, and components (SSCs). A detailed list of safety-related SSCs at the component level for HNP-1 and HNP-2 is contained in Volume 3 of System Evaluation Document (SED). The criteria used for identifying the safety-related SSCs are described in Volume 3 of the SED and are procedurally controlled. The list of safety-related SSCs at the component level is maintained current. Changes to Volume 3 of the SED are reviewed pursuant to 10 CFR 50.59.

A general list of the SSCs covered under the QA Program is provided in HNP-1-FSAR table D.9-1 and HNP-2-FSAR table 17-2-2. Systems included in these tables contain at least one safety-related item; however, portions of some systems may not be considered safety-related. Due to the high-level nature of the lists, only major plant modifications are expected to affect the content of these FSAR tables

Consistent with HNP-2-FSAR paragraph 1.1.8.7, HNP-1-FSAR table D.9-1 and HNP-2-FSAR table 17.2-2 are designated as *Historical*.

TABLE D.9-1 (SHEET 1 OF 9)

LIST OF SAFETY-RELATED STRUCTURES, SYSTEMS, AND COMPONENTS[(a)]

1.0 Buildings and Structures

- *1.1 Intake Structure (common to both units)*
- *1.2 Main Stack (common to both units)*
- *1.3 Buildings*
  - *1.3.1 Reactor Building (including spent-fuel storage pool and new-fuel storage vault)*
  - *1.3.2 Control Building (common to both units)*
  - *1.3.3 Diesel Generator Building (common to both units)*
  - *1.3.4 Parts of Other Structures' Housing and/or Supporting Class 1 Equipment*
    - *1.3.4.1 Condensate Storage Tank Enclosure*
    - *1.3.4.2 Liquid Nitrogen Storage Tank and Foundation*
    - *1.3.4.3 Diesel Generator Fuel Oil Storage Tanks*
- *1.4 Primary Containment*

2.0 Mechanical Systems and Components

- *2.1 Nuclear Boiler System*
  - *2.1.1 Reactor Pressure Vessel (RPV)*
    - *2.1.1.1 Vessel*
    - *2.1.1.2 Head*
    - *2.1.1.3 Head Studs*
    - *2.1.1.4 Control Rod Housings (including guide tubes)*
    - *2.1.1.5 Stabilizers*
  - *2.1.2 Internals*
    - *2.1.2.1 Dryer/Separator Holddown Bolts*
    - *2.1.2.2 Feedwater Sparger*
    - *2.1.2.3 Core Shroud*
    - *2.1.2.4 Jet Pump Assemblies*
    - *2.1.2.5 Core Support Structures*
    - *2.1.2.6 Flow Baffles, Guides, and Orifices*
    - *2.1.2.7 Core Spray Sparger*
    - *2.1.2.8 Incore Flux Monitor Housing*
    - *2.1.2.9 Power Range Monitors*
    - *2.1.2.10 Control Rods (inside RPV)*

TABLE D.9-1 (SHEET 2 OF 9)

2.1.3 Valves

2.1.3.1 Steam Isolation Valves
2.1.3.2 Feedwater Check Valves
2.1.3.3 Safety Relief Valves
2.1.3.4 Safety Relief Valve Discharge Vacuum Breakers

2.1.4 Pipe and Fittings

2.1.4.1 Up to Second Containment Isolation Valve External to Drywell
2.1.4.2 SRV Discharge Headers

2.1.5 Instrumentation and Control (essential)

2.2 Recirculation System

2.2.1 Recirculation Pumps and Motors (structural integrity post-design basis accident (DBA))
2.2.2 Isolation Valves (suction valve - structural integrity only)
2.2.3 Pipe and Fittings
2.2.4 Instrumentation and Controls (essential)
2.2.5 Recirculation Pump Trips

2.3 Control Rod Drive System

2.3.1 Hydraulic System

2.3.1.1 Valves (essential)
2.3.1.2 Scram Discharge Header
2.3.1.3 Pipe and Fittings (essential)

2.3.2 Hydraulic Control Unit (HCU)

2.3.2.1 HCU Package
2.3.2.2 Foundations and Bolting
2.3.2.3 Pipe and Fitting

2.3.3 Rod Drive Mechanisms

2.3.3.1 Support Assembly
2.3.3.2 Piston Mechanism
2.3.3.3 O-Rings and Seals
2.3.3.4 Couplings and Latches

2.3.4 Instrumentation and Controls (partial)

TABLE D.9-1 (SHEET 3 OF 9)

2.4 Standby Liquid Control System

- *2.4.1 Storage Tank*
- *2.4.2 Pumps and Motors*
- *2.4.3 Explosive Valves*
- *2.4.4 Accumulators*
- *2.4.5 Relief Valves*
- *2.4.6 Pipe and Fittings (partial)*
- *2.4.7 Instrumentation and Controls (essential)*

2.5 Residual Heat Removal (RHR) System

- *2.5.1 Heat Exchangers*
- *2.5.2 Pumps and Motors*
- *2.5.3 Relief Valves*
- *2.5.4 Check Valves*
- *2.5.5 Control Valves*
- *2.5.6 Pipe and Fittings (partial)*
- *2.5.7 Instrumentation and Controls (essential)*

2.6 Core Spray System

- *2.6.1 Pumps and Motors*
- *2.6.2 Control Valves*
- *2.6.3 Check Valves*
- *2.6.4 Pipe and Fittings*
- *2.6.5 Instrumentation and Controls (essential)*

2.7 High-Pressure Coolant Injection (HPCI) System

- *2.7.1 Turbine and Pumps*
  - *2.7.1.1 Turbine*
  - *2.7.1.2 Steam Valves*
  - *2.7.1.3 Pumps*
- *2.7.2 Valves*
  - *2.7.2.1 Control Valves*
  - *2.7.2.2 Relief Valves*
  - *2.7.2.3 Check Valves*
- *2.7.3 Pipe and Fittings (partial)*
- *2.7.4 Instrumentation and Controls (essential)*

TABLE D.9-1 (SHEET 4 OF 9)

2.8 Reactor Core Isolation Cooling (RCIC) System

2.8.1 Turbine and Pump

2.8.1.1 Turbine
2.8.1.2 Steam Valves
2.8.1.3 Pump

2.8.2 Valves

2.8.2.1 Control Valves
2.8.2.2 Check Valves
2.8.2.3 Relief Valves

2.8.3 Pipe and Fittings (partial)
2.8.4 Instrumentation and Controls (essential)

2.9 Reactor Building Ventilation System

2.9.1 Normal Ventilation System

2.9.1.1 Intake Dampers (forming secondary containment boundary)
2.9.1.2 Exhaust Dampers (forming secondary containment boundary)
2.9.1.3 Safeguard Equipment Emergency Coolers
2.9.1.4 Instrumentation and Controls (for items 2.9.1.1 through 2.9.1.3)

2.10 Standby Gas Treatment System

2.10.1 Preheaters
2.10.2 Filters
2.10.3 Fans
2.10.4 Valves
2.10.5 Ducting (filter housing and portions forming boundary of secondary containment)
2.10.6 Instrumentation and Control (essential)

2.11 Fuel Storage, Refueling, Handling and Servicing System

2.11.1 Fuel
2.11.2 New-Fuel Racks
2.11.3 Spent-Fuel Racks
2.11.4 Control Rods Racks
2.11.5 Damaged Fuel Racks
2.11.6 Spent-Fuel Cask
2.11.7 Refueling Platform
2.11.8 RPV Head Strongback

TABLE D.9-1 (SHEET 5 OF 9)

2.11.9 Dryer/Separator Sling
2.11.10 Service Platform – NO LONGER AVAILABLE
2.11.11 Bridge Crane

2.12 Traversing Incore Probe (TIP) System (essential)

2.12.1 Tube Indexer
2.12.2 Storage Cask
2.12.3 Disposal Cask
2.12.4 Cable Drive
2.12.5 Shear Valves

2.13 Radiation Monitoring

2.13.1 Neutron Monitoring System (partial)
2.13.2 Process Radiation Monitoring System (partial)

2.14 Reactor Water Cleanup System

2.14.1 Pipe and Fittings (partial)
2.14.2 Instrumentation and Controls (essential)
2.14.3 Isolation Valves

2.15 Plant Service Water Pumps and Motors, Associated Piping, Valves, Instrumentation and Controls (essential), and Heat Exchangers

2.16 Plant Instrument Air System (as required for safe shutdown)

2.17 Main Control Room Control Panels and Devices for Seismic Class 1 Equipment

2.18 Pipe Supports and Hangers for Seismic Class 1 Pipe

2.19 Diesel Generator Building Ventilation System

2.20 Station Battery and Emergency Switchgear Rooms Ventilation System(s)

2.21 Drywell Pneumatic System (as required for safe shutdown)

2.22 Nitrogen Makeup System (as required for DBA mitigation)

2.23 Drywell Purge System (as required for DBA mitigation)

2.24 (deleted)

TABLE D.9-1 (SHEET 6 OF 9)

2.25 Fuel Pool Cooling and Cleanup

- *2.25.1 Pipe and Fittings*
- *2.25.2 Valves*

2.26 RHR Service Water System

- *2.26.1 Cross-Connect Piping System (within second automatic isolation valve)*
- *2.26.2 Piping*
- *2.26.3 Pumps*
- *2.26.4 Pump Motors*
- *2.26.5 Isolation Valves*
- *2.26.6 Other Valves*
- *2.26.7 Electrical Modules (with safety function)*
- *2.26.8 Cable (with safety function)*

2.27 Control Room Ventilation System

- *2.27.1 Pre-Filters and Filters*
- *2.27.2 Fans*
- *2.27.3 Valves*
- *2.27.4 Dampers*
- *2.27.5 Ducting*
- *2.27.6 Louvers*
- *2.27.7 Instrumentation and Controls (essential)*
- *2.27.8 Heaters, Coolers, and Condensing Units*

2.28 Refueling Floor Ventilation System

- *2.28.1 Intake and Exhaust Dampers*
- *2.28.2 Instrumentation and Controls (essential)*

2.29 Intake Structure Ventilation System

2.30 Leak Detection System

2.31 Whip Restraints and Jet Impingement Barriers

2.32 Primary Containment Isolation System

- *2.32.1 Valves*
- *2.32.2 Instrumentation and Controls*

2.33 Reactor Protection System

- *2.33.1 Instrumentation and Controls*

TABLE D.9-1 (SHEET 7 OF 9)

2.34 Post-Accident Monitoring System

2.35 Torus Drainage and Purification System

2.35.1 Isolation Valves
2.35.2 Pipe and Fittings (essential)
2.35.3 Instrumentation and Controls (essential)

2.36 Sampling System

2.36.1 Primary Containment H_2O_2 Analyzers
2.36.2 Valves (essential)
2.36.3 Pipe and Fittings (essential)
2.36.4 Instrumentation and Controls (essential)

2.37 Reactor Building Closed Cooling Water System (inside containment up to external containment isolation valves)

3.0 Electrical

3.1 Switchgear Associated With Engineering Safeguards

3.1.1 4160-V Emergency Buses

3.1.1.1 4.16-kV Switchgear Bus (1E R22-S005)
3.1.1.2 4.16-kV Switchgear Bus (1F R22-S006)
3.1.1.3 4.16-kV Switchgear Bus (1G R22-S007)

3.1.2 600-V Emergency Load Centers and Bus Ducts

3.1.2.1 600-V Load Centers Bus 1C (R23-S003)
3.1.2.2 600-V Load Centers Bus 1D (R23-S004)
3.1.2.3 600-V Bus Ducts Associated with Load Centers

3.2 Switchboards and Panels

3.2.1 Control Boards

3.2.1.1 Reactor and Containment Cooling and Isolation Board
3.2.1.2 Power Range Neutron Monitoring Cabinet
3.2.1.3 Channel A Primary Isolation and Reactor Protection System Vertical Board
3.2.1.4 Channel B Primary Isolation and RPS Vertical Board
3.2.1.5 Steam, Feedwater Condensate, Circulating, and Service Water Benchboard
3.2.1.6 Emergency Diesel Generator No. 1 (BB+VB)

TABLE D.9-1 (SHEET 8 OF 9)

3.2.1.7 Emergency Diesel Generator No. 2 (BB+VB)
3.2.1.8 Emergency Diesel Generator No. 3 (BB+VB)

3.2.2 Protective Relay Board

3.2.2.1 Channel A RHR Relay Vertical Board
3.2.2.2 Channel B RHR Relay Vertical Board
3.2.2.3 HPCI Relay Vertical Board
3.2.2.4 RCIC Relay Vertical Board
3.2.2.5 Inboard Isolation Valve Relay Vertical Board
3.2.2.6 Outboard Isolation Valve Relay Vertical Board
3.2.2.7 Channel A CS Relay Vertical Relay Board
3.2.2.8 Channel B CS Relay Vertical Board
3.2.2.9 Auto Blockdown Relay Vertical Board
3.2.2.10 Heating, Ventilating, and Air-Conditioning Control Boards (H11-P654 and H11-P657)
3.2.2.11 Local Panels Continuing Essential System Controls or Components

3.2.3 Motor Control Centers (MCCs)

3.2.3.1 600-ac Essential MCCs (reactor building)
3.2.3.2 250-dc Essential MCCs (reactor building)
3.2.3.3 600/208 V-ac Essential MCCs (diesel building)
3.2.3.4 600/208 V-ac Essential MCCs (control building)

3.2.4 dc Switchgear in Control Building

3.2.4.1 250 V-dc Switchgear Bus 1A (R22-S016)
3.2.4.2 250 V-dc Switchgear Bus 1B (R22-S017)

3.3 Raceways Associated with Engineering Safeguards

3.3.1 Conduit Supports
3.3.2 Cable Tray Supports
3.3.3 Pull Boxes and Junction Boxes
3.3.4 Underground Ducts, Fittings, and Encasement

3.4 Cables Associated With Engineering Safeguards

3.4.1 Instrument Cables
3.4.2 Emergency 600-V and 208/120-V Power and Control Cables
3.4.3 4160-V Power Cables

TABLE D.9-1 (SHEET 9 OF 9)

3.5 dc Equipment

3.5.1 Battery and Accessories

3.5.1.1 125/250-V Station Batteries
3.5.1.2 125-V Emergency Diesel Batteries

3.5.2 Battery Charger Units

3.5.2.1 Battery Charger Units for Station Batteries
3.5.2.2 Battery Chargers Units for Emergency Diesel batteries

3.6 Generators

3.6.1 Emergency Diesel Generator Sets
3.6.2 Neutral Grounding Resistors for Emergency Diesel Generator Sets

3.7 Miscellaneous Electrical Items

3.7.1 ac/dc Essential Distribution Cabinets (control and diesel buildings)
3.7.2 Drywell Penetrations
3.7.3 Lighting and Miscellaneous Distribution Transformers for Emergency Services

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a. Listed systems include at least one safety-related item.

APPENDIX E

OFF-GAS RELEASE RATE LIMIT CALCULATIONS

Information pertaining to off-gas release rate limit calculations applies to both HNP-1 and HNP-2. Refer to the HNP-2-FSAR locations specified below for the following off-gas release rate limit calculation topics:

	Topic	HNP-2-FSAR Location
1.	Source-Term Modeling and Input Data	11.2.4 and 11.3.4
2.	Meteorological Diffusion Calculations	2.3.5
3.	Hydrological Diffusion Calculations	11.2.4.1.3
4.	Doses From Liquid Effluents	11.2.4.1.1
5.	Doses From Gaseous Effluents	11.3.4.1.5
6.	Compliance With 10 CFR 50 Appendix I	11.2.4

APPENDIX F

CONFORMANCE TO ATOMIC ENERGY COMMISSION (AEC) CRITERIA

F.1 SUMMARY DESCRIPTION

Section F.2 of this appendix contains an evaluation of the design bases of Hatch Nuclear Plant-Unit 1 (HNP-1) based on the current understanding of the intent of the "General Design Criteria for Nuclear Power Plant Construction," issued for comment in July 1967.

Section F.3 contains an evaluation of the design bases of HNP-1 based on the current understanding of the intent of the "General Design Criteria for Nuclear Power Plants," effective May 21, 1971, and subsequently amended July 7, 1971. Each of the AEC criteria is followed by a discussion of the plant design. Applicable references are made to facilitate comparisons.

The HNP-1 construction permit was received under the 70 general design criteria discussed in section F.2. The HNP-1 design bases were not, therefore, developed in consideration of the 64 new general design criteria discussed in section F.3. The applicant has, however, evaluated the HNP-1 design bases against the new criteria.

F.2 CONFORMANCE TO 1967 GENERAL DESIGN CRITERIA

F.2.1 GROUP I - OVERALL PLANT REQUIREMENTS (CRITERIA 1 THROUGH 5)

The criteria in Group I (table F.2-1) establish standards for the quality and performance of systems and components essential to the prevention of accidents or the mitigation of their consequences, fire protection, safety of shared systems and components, and recordkeeping.

The quality assurance program directed by the applicant covers the design, procurement, fabrication, manufacture, erection, and testing of components and systems for the plant. This program also ensures the use of applicable design and construction codes and standards (criterion 1). Structures and equipment required to enable the facility to withstand, without loss of the capability to protect the public, the additional forces possibly imposed by natural phenomena such as earthquakes, tornadoes, floods, winds, and other local effects are designed to performance standards (criterion 2). The separation of redundant critical equipment is utilized in the design of the plant to minimize the effects of fires. Noncombustible and fire resistant materials are used whenever practical throughout the facility (criterion 3).

The design of safety-related systems shared by Units 1 and 2 ensures that safety is not impaired as a result of the system sharing (criterion 4).

Records of design, fabrication, and construction for this facility are stored or maintained either under the applicant's control or are available to the applicant for inspection (criterion 5).

F.2.2 GROUP II - PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS (CRITERIA 6 THROUGH 10)

The criteria in Group II (table F.2-2) require that nuclear power facilities be provided with multiple barriers to protect the public against the inadvertent release of radioactive material to the environs.

The reactor core is designed so that there is no inherent tendency for sudden divergent oscillation of operating characteristics, for divergent power transients in any mode of plant operation, or for uncontrollable oscillations (criteria 6 and 7). The basis of the reactor core design, in combination with the plant equipment characteristics, nuclear instrumentation system, and the reactor protection system (RPS), is to provide margins to ensure that fuel damage does not occur during normal operation or that operational transients caused by a single operator error or single equipment malfunction do not occur (criteria 6 and 7). The reactor is designed so that the overall power coefficient in the power operating range is not positive (criterion 8).

The reactor coolant pressure boundary (RCPB) or the nuclear system primary barrier is designed to carry its dead weight and specified live loads separately or concurrently, e.g., pressure, temperature, vibration and seismic loads prescribed for the plant. Provisions are made to control or shut down the reactor coolant system in the event of an operating equipment malfunction or leakage of coolant from the system. The reactor vessel and support structures are designed within the limits of applicable criteria for low-probability accident conditions to withstand the forces that would be created by the postulated design *loss-of-coolant accident (LOCA) inside the drywell concurrent with the plant design earthquake loads (criterion 9).*

The plant radioactive material barriers are the basic features that minimize release of radioactive materials and associated doses. This plant provides the following means of containing or mitigating the release of fission products:

- *High-density ceramic UO_2 fuel.*
- *High-integrity Zircaloy cladding.*
- *Reactor vessel and connected piping, pumps, and valves that make up the nuclear system process barrier.*
- *Drywell suppression chamber (primary containment).*
- *Reactor building, standby gas treatment system (SGTS), and main stack.*

The primary containment, together with the engineered safety features (ESFs) is designed, fabricated, and erected to accommodate without failure the maximum pressure and temperature resulting from, or subsequent to, failure of a coolant pipe within the primary containment, including the instantaneous circumferential rupture of one reactor recirculation loop pipe. The reactor building encompasses the primary containment and, in conjunction with the SGTS and main stack, provides secondary containment when the primary containment is closed and in service, in addition to providing containment when the primary containment is open, e.g., during refueling periods. The two containments and the other ESFs are designed and maintained so that offsite doses resulting from postulated design basis accidents (DBAs) are below the guideline values set forth in 10 CFR 100 (criterion 10).

F.2.3 GROUP III - NUCLEAR AND RADIATION CONTROLS (CRITERIA 11 THROUGH 18)

The criteria in Group III (table F.2-3) identify and define the plant instrumentation and control systems necessary to maintain the plant in a safe operational status and also to provide adequate radiation shielding, radiation monitoring, fission process controls, and the effective sensing of abnormal conditions for initiation of ESFs. The necessary plant controls, instrumentation, and alarms for safe and orderly operation are located in the main control room (MCR) (criteria 11, 12, 13, and 16).

The plant is provided with a shielded MCR to permit access and occupancy during DBA situations, to shut down the reactor, and to maintain it in the safe condition. Nevertheless, equipment is provided to bring the plant to a safe shutdown from outside the MCR if it is necessary to evacuate the MCR (criterion 11).

The performance of the reactor core and the indication of reactor power level are continuously monitored by the nuclear instrumentation system (criterion 13). The RPS, independent from the plant process control systems, overrides all other controls to initiate required safety actions. The RPS automatically initiates appropriate action whenever the plant conditions approach established operational limits. The system acts specifically to initiate the emergency core cooling system (ECCS) (criteria 12, 13, 14, and

15). The plant radiation and process monitoring systems are provided for monitoring significant parameters from specific plant process systems and specific areas, including the plant effluents, and for providing alarms and signals indicating appropriate corrective actions. Monitoring and alarm instrumentation is provided for fuel and waste storage and for handling areas (criteria 17 and 18).

F.2.4 GROUP IV - RELIABILITY AND TESTABILITY OF PROTECTION SYSTEMS (CRITERIA 19 THROUGH 26)

The criteria in Group IV (table F.2-4) identify and establish requirements with regard to the functional reliability, inservice testability, redundancy, physical and electrical independence and separation, and fail-safe design of the protection systems.

The protection systems act to shut down the reactor, close primary containment isolation valves, and initiate the operation of the ECCS. The protection systems automatically override the plant normal operational control system (functions independently) to initiate appropriate protective action whenever the plant conditions monitored by the system, e.g., neutron flux, containment pressure, reactor vessel pressure, exceed established limits (criterion 22). By means of a duel-channel protection system with complete redundancy in each channel, no loss of the protection systems can occur by either single component failure or removal from service. The RPS is designed so that a plant transient or accident is sensed by different parametric measurements; e.g., a LOCA is detected by high drywell pressure and reactor low water level monitors. At least two instrument channels are provided to initiate each protection function (criterion 20). Components of the redundant subsystems can be removed from service for testing and maintenance without negating the ability of the protection system to perform its functions upon receipt of the appropriate signals (criterion 19, 20, and 21). The design of the protection systems provides a means for testing and facilities maintenance and for troubleshooting while the reactor is at power operation without impeding the plant operation or impairing the safety function (criterion 25). The systems' electrical power requirements are supplied from independent, redundant sources. Alternate sources of power are provided to permit the required functioning of the protection systems in the event of loss of offsite power (LOSP) (criterion 24). The system circuits are separated to preclude a circuit fault from inducing a fault in another circuit and to reduce the likelihood that adverse conditions will encompass more than one circuit. The system sensors are electrically and physically separated, with special attention given to assure that the sensors in any one trip channel are not placed in the same local area or connected to the same power source or process measurement line. The systems' internal wiring and external cable routing are arranged to reduce any external influence on the system performance (criteria 23 and 24). Systems essential to the protection function are designed to fail-safe in their likely failure modes. A failure of any one protection system inputs or subsystem component produces a trip in one of the two channels. This condition is insufficient to produce a reactor scram, but the system is ready to perform its protective function upon another trip, either by failure or by exceeding the preset trip in the other channel (criterion 26).

F.2.5 GROUP V - REACTIVITY CONTROL (CRITERIA 27 THROUGH 32)

The criteria in Group V (table F.2-5) establish the reactor core reactivity insertion and withdrawal rate limitations and the means to control the plant operations within these limits.

The plant design contains two independent reactivity control systems of different principles. In the first, the control of reactivity is provided by a combination of movable control rods and reactor coolant recirculation system flow for each reactor. These systems accommodate fuel burnup, load changes, and long-term reactivity changes. Reactor shutdown by the control rod drive system is sufficiently rapid to prevent violation of fuel damage limits for normal operation and all abnormal operating transients. The second system, a standby liquid control system, is provided as an independent backup shutdown system to cover situations limiting the use of the operational reactivity control system. This system is designed to shut down the reactor and maintain the shutdown condition during reactor cooldown (criteria 27, 28, and 29).

The reactor core consists of (criteria 27 and 31):

- *A reactivity response that regulates or damps changes in power level and spatial distributions of power production to a level consistent with safe and efficient operation.*
- *A negative reactivity feedback consistent with the requirements of overall plant nuclear-hydrodynamic stability.*
- *A strong negative reactivity feedback under severe power transient conditions.*

The reactivity control system is designed such that under conditions of normal operation sufficient reactivity compensation is always available to make the reactor adequately subcritical from its most reactive condition. Means are provided for continuous regulation of the reactor core excess reactivity and reactivity distribution. Shutdown margins greater than the maximum worth of the most effective control rod when fully withdrawn are provided (criteria 29 and 30). This system is also designed to compensate and for positive and negative reactivity changes resulting from changing nuclear coefficients, fuel depletion, and fission product transients and buildup (criterion 29). The system is designed so that control rod worths and the rate at which reactivity can be added are limited to assure that the design basis reactivity accident will not damage the reactor coolant system or disrupt the reactor core, its support structures, or other vessel internals, impairing the ECCS effectiveness. Acceptable fuel damage limits are not exceeded for any reactivity transient resulting from a single equipment malfunction or operator error (criteria 29, 31, and 32).

F.2.6 GROUP VI - REACTOR COOLANT PRESSURE BOUNDARY (CRITERIA 33 THROUGH 36)

The criteria in Group VI (table F.2-6) establish the RCPB design requirements and identify the means used to satisfy these design requirements. The RCPB may be referred to as the nuclear system primary barrier. (See section 1.2, Definitions.)

The inherent safety features of the reactor core design, in combination with certain ESFs (control rod velocity limiter and control rod housing) and the plant reactivity control system, are such that the consequences of the most severe potential nuclear excursion accident caused by a single component failure within the reactivity control system (rod drop accident) cannot result in damage, either by motion or rupture, to the RCPB (criterion 33). The American Society of Mechancial Engineers and the American National Standards Institute codes are used as the established and acceptable criteria for design, fabrication, and operation of components of the RCPB which is designed and fabricated to meet the minimum requirements described in appendices A and C (criterion 34).

The brittle-fracture failure mode of the RCPB system components is prevented by control of the notch toughness properties of the ferritic steel components. The control is exercised in the selection of materials and fabrication of equipment and components. In the design, appropriate consideration is given to the different notch toughness requirements of each of the various ferritic steel product forms, including weld and heat-affected zones. In this way, assurance is provided that brittle fracture is prevented under all potential service loading temperatures (criterion 35).

The RCPB is given a hydrostatic test, in accordance with code requirements, prior to initial reactor startup. The system is checked for leaks, and abnormal conditions are corrected prior to reactor startup. A hydrostatic test, not to exceed system operating pressure, can be made on the RCPB following each removal and replacement of the reactor vessel head; a quality assurance program is also followed during the entire fabrication (criterion 36). Vessel material surveillance samples are located within the reactor primary vessel to enable periodic monitoring of material properties with exposure. The program includes specimens of the base metal, heat-affected zone metal, and standards specimens. Leakage from the RCPB is monitored during reactor operation (criterion 36).

F.2.7 GROUP VII - ENGINEERED SAFETY FEATURES (CRITERIA 37 THROUGH 65)

The criteria in Group VII (table F.2-7) establish requirements with respect to:

- *Incorporation of ESFs.*
- *Independence, redundancy, capability, testability, inspectability, and reliability of ESFs.*
- *Suitability of each ESF for its intended duty.*
- *Justification that each ESF's capability envelopes all DBAs considered.*

The ESFs may be referred to as engineered safeguards that mitigate the consequences of postulated DBAs. (See section 1.2, Definitions, and table F.2-10).

The normal plant control systems maintain plant variables within operating limits. These systems are thoroughly engineered and backed up by a significant amount of experience in system design and operation. Even if an improbable maloperation or equipment failure were to occur, including a circumferential rupture of any pipe in the RCPB with unobstructed discharge from both ends, an extensive system of ESFs limits the transient and the radiological effects to below the guideline values set forth in 10 CFR 100 (criterion 37). These ESFs include those offering protection against a reactivity *excursion, those acting to reduce the consequences of postulated DBAs, and those providing core cooling in the event of a loss of normal cooling (criterion 37). Sufficient offsite and standby (redundant, independent, and testable) auxiliary sources of electrical power are provided to attain prompt shutdown and continued maintenance of the plant in a safe condition. The capacity of the offsite and onsite power sources are independently adequate to accomplish the required FSF functions, assuming a failure of a single active component in each power system (criterion 39).*

Each ESF is designed to provide high reliability and testability, and specific provisions are made in each to demonstrate operability and performance capabilities (criterion 38). Components of the ESFs required to function after DBAs are designed to withstand credible effects from a LOCA and are protected without impairment of performance capability from credible missiles generated by plant equipment failures (criteria 40, 42, and 43). The ECCS is designed to provide at least two different systems of different principles to prevent excessive fuel clad temperature over the entire spectrum of postulated coolant boundary breaks. Such capability is available notwithstanding a LOSP. The ECCS is designed to various levels of component redundancy such that no single active component failure in addition to the accident can prevent core coolant (criteria 41 and 44). To assure that the ECCS will function properly, specific provisions have been made to provide capability for testing the sequential operability and functional performance of each individual system (criteria 46, 47, and 48). Design provisions have also been made to facilitate physical and visual inspection of the ECCS components (criterion 45).

The primary containment structure, including access openings and penetrations, is designed to withstand the peak pressure and temperatures which could occur due to the postulated design basis LOCA. The containment design includes allowance for energy addition from metal-water reactions beyond conditions which would occur with normal operation of the ECCS (criterion 49).

The drywell is not pressurized or subjected to substantial stress at temperatures below 30°F above nil ductility transition (NDT) for the head and penetration materials (criterion 50). The effects of an accidental rupture of a primary coolant pipe outside the primary containment are limited by the ESFs such that offsite doses are below the guideline values of 10 CFR 100 (criterion 51).

Provisions are made for the removal of heat from within the plant containment and for isolation of the various process system lines as may be necessary to maintain the integrity of the plant containment systems as long as necessary following the various postulated DBAs. Process lines that penetrate the primary containment and connect to the reactor coolant system, or to the primary containment free space, are provided with at least two isolation valves in series (criterion 53). The plant design includes preoperational and postoperational pressure and leak rate testing capability (criteria 54 and 55). Provisions are made for demonstrating the functional performance of the primary containment isolation valves and leak testing of penetrations having seals or expansion bellows (criteria 56 and 57). The pressure suppression system and the containment cooling system provide two different means for containment heat removal under accident conditions so that the peak containment pressure would be less than the primary containment maximum allowable pressure (criterion 52). Ability to demonstrate operability, test the functional performance, and inspect the active components of the containment cooling system is provided (criteria 58, 59, 60, and 61). The SGTS is designed to permit periodic testing of the system performance (criterion 64); the system can be physically inspected and its operability demonstrated (criteria 62, 63, and 65).

F.2.8 GROUP VIII - FUEL AND WASTE STORAGE SYSTEMS (CRITERIA 66 THROUGH 69)

The criteria in Group VIII (table F.2-8) establish requirements applicable to fuel and waste storage systems. Fuel handling and storage facilities are provided to preclude accidental criticality and to provide sufficient cooling for spent-fuel (criteria 66 and 67). The new fuel storage vault racks (located in the reactor building) are top entry and designed to prevent an accidental critical array even if the vault were flooded. Vault drainage is provided to prevent possible water collection (criterion 66). The handling and storage of spent-fuel takes place entirely within the reactor building which provides containment (criterion 69). The spent-fuel storage pool has provisions to maintain water clarity, control temperature, and monitor water and radiation level. Water depth in the pool provides sufficient shielding for normal reactor building occupancy by operating personnel. The racks in which spent-fuel assemblies are placed are designed and arranged to ensure subcriticality in the storage pool (criteria 66, 67, 68, and 69). The fuel pool cooling and cleanup system is designed to maintain the pool water temperature (decay heat removal), maintain water clarity (safe fuel movement), and control water radioactivity (shielding and effluent release control) (criteria 66, 67, and 68). Accessible portions of the reactor and radwaste buildings have sufficient shielding to maintain dose rates within the guidelines of 10 CFR 20 (criterion 68). The radwaste facilities are designed to prevent accidental release of undue amounts of radioactive materials to the environs (criterion 69).

F.2.9 GROUP IX - PLANT EFFLUENTS (CRITERION 70)

The criterion in Group IX (table F.2-9) establishes requirements to limit releases of radioactive materials.

The plant radioactive waste systems, which include the liquid, gaseous, and solid radwaste, are designed to maintain the offsite radiation exposure to levels below the limits of 10 CFR 20. The plant ESF systems, including the containment barriers, are designed to limit the offsite doses under various DBAs to levels below 10 CFR 100 guideline values. The off-gas system is designed with sufficient holdup retention capacity so that during normal plant operation the controlled release of radioactive materials does not exceed the established release limits (criterion 70).

TABLE F.2-1

ATOMIC ENERGY COMMISSION (AEC)
GENERAL DESIGN CRITERIA - GROUP I
OVERALL PLANT REQUIREMENTS

Criterion		Conformance[a]
1.	Quality standards	Chapter 1, appendix D
2.	Performance standards	Chapters 1, 2, 5, 8, and 12 and appendices A and C
3.	Fire protection	Chapters 5, 10, 12, and 13
4.	Sharing of systems	Chapters 1, 8, 10, and 12
5.	Records requirements	Appendix D

a. *Referenced to Edwin I. Hatch-Unit 1 Final Safety Analysis Report (HNP-1-FSAR) chapters and appendices.*

TABLE F.2-2

AEC GENERAL DESIGN CRITERIA - GROUP II
PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS

Criterion		Conformance[a]
6.	Reactor core design	Chapters 1, 3, 4, 7, and 14
7.	Suppression of power oscillations	Chapters 1, 3, 4, 7, and 14
8.	Overall power coefficient	Chapters 1, 3, and 7
9.	RCPB	Chapters 1, 4, 7, and 14 and appendix A
10.	Containment	Chapters 5 and 14

a. *Referenced to HNP-1-FSAR chapters and appendices.*

TABLE F.2-3

AEC GENERAL DESIGN CRITERIA - GROUP III NUCLEAR AND RADIATION CONTROLS

Criterion	*Conformance*[a]
11. MCR	*Chapters 1, 7, 10, and 12*
12. Instrumentation and control system	*Chapters 1, 3, 4, and 7*
13. Fission process monitors and controls	*Chapters 1, 3, and 7*
14. RPS	*Chapters 1, 3, 4, 6, 7, 8, and 14*
15. ESFs protection system	*Chapters 1 and 7*
16. Monitoring RCPB	*Chapters 1, 4, and 7*
17. Monitoring radioactive releases	*Chapters 1, 7, and 9*
18. Monitoring fuel and waste storage	*Chapters 1, 7, 9, and 10*

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-4

AEC GENERAL DESIGN CRITERIA - GROUP IV
RELIABILITY AND TESTABILITY OF PROTECTION SYSTEMS

Criterion	*Conformance*[a]
19. Reliability	*Chapters 1, 7, 8, and 14*
20. Redundancy and independence	*Chapters 1, 7, 8, and 14*
21. Single-failure definition	*Chapters 1 and 14*
22. Separation of protection and control instrumentation systems	*Chapters 1, 7, and 8*
23. Protection against multiple disabilities	*Chapters 1, 7, 8, and 14*
24. Emergency power	*Chapters 1, 7, 8, and 14*
25. Demonstration of functional operability	*Chapters 1, 7, 8, and 13*
26. Fail-safe design	*Chapters 1, 6, 7, and 8*

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-5

AEC GENERAL DESIGN CRITERIA - GROUP V
REACTIVITY CONTROL

	Criterion	Conformance[a]
27.	Redundancy	Chapters 1, 3, and 7
28.	Hot shutdown capability	Chapters 1, 3, 7, and 14
29.	Shutdown capability	Chapters 1, 3, 7, and 14
30.	Holddown capability	Chapters 1 and 3
31.	Control systems malfunction	Chapters 1, 3, 7, and 14
32.	Maximum worth of control rods	Chapters 1, 3, 7, and 14

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-6

AEC GENERAL DESIGN CRITERIA - GROUP VI RCPB

Criterion	Conformance[a]
33. Capability	Chapters 1, 3, 4, and appendix A
34. Rapid propagation failure prevention	Chapters 3, 4, and appendices A and D
35. Brittle-fracture prevention	Chapter 4, appendix A
36. Surveillance	Chapter 4, appendix A

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-7 (SHEET 1 OF 2)

AEC GENERAL DESIGN CRITERIA - GROUP VII
ESFs

	Criterion	*Conformance*[a]
37.	*Basis for design*	*Chapters 1, 3, 4, 5, 6, 7, 8, 10, and 14*
38.	*Reliability and testability*	*Chapters 1, 3, 4, 5, 6, 7, 8, and 10*
39.	*Emergency power*	*Chapters 7 and 8*
40.	*Missile protection*	*Chapter 12*
41.	*Performance capability*	*Chapters 5, 6, 7, 8, and 14*
42.	*Components capability*	*Chapters 3, 5, 6, 7, 8, and 14*
43.	*Accident aggravation protection*	*Chapters 3, 5, 6, 7, 8, 12, and 14*
44.	*Emergency core cooling system (ECCS) capability*	*Chapters 6, 7, and 14*
45.	*ECCS inspection*	*Chapters 3, 4, 6, and 13*
46.	*Testing of ECCS components*	*Chapters 6, 7, 13, and 14*
47.	*ECCS testing*	*Chapters 6, 7, and 13*
48.	*Testing of ECCS operational sequence*	*Chapters 6, 7, 8, and 13*
49.	*Containment design basis*	*Chapters 1, 5, 6, 12, and 14*
50.	*NDT requirement for containment material*	*Chapters 4 and 5*
51.	*RCPB outside containment*	*Chapters 1, 4, 5, 12, and 14*
52.	*Containment heat removal systems*	*Chapters 1, 5, 6, and 14*
53.	*Containment isolation valves*	*Chapters 1, 4, 5, and 7*
54.	*Containment leakage rate testing*	*Chapters 5 and 13*

TABLE F.2-7 (SHEET 2 OF 2)

	Criterion	*Conformance*[a]
55.	*Containment periodic leakage rate testing*	*Chapters 5 and 13*
56.	*Provisions for testing penetrations*	*Chapters 5 and 13*
57.	*Provisions for testing isolation valves*	*Chapters 4, 5, 7, and 13*
58.	*Inspection of containment pressure - reducing system*	*Chapters 5, 6, and 13*
59.	*Testing of containment pressure reducing system components*	*Chapters 5, 6, 7, and 13*
60.	*Testing of containment spray system*	*Chapters 4, 6, and 7*
61.	*Testing of containment pressure - reducing system operational sequence*	*Chapters 6, 7, and 8*
62.	*Air cleanup system inspection*	*Chapters 5, 10, and 13*
63.	*Testing of air cleanup system components*	*Chapters 5, 10, and 13*
64.	*Air cleanup system testing*	*Chapters 5, 10, and 13*
65.	*Testing of air cleanup system operational sequence*	*Chapters 5, 10, and 13*

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-8

AEC GENERAL DESIGN CRITERIA - GROUP VIII FUEL AND WASTE STORAGE SYSTEMS

Criterion	Conformance[a]
66. Prevention of criticality	*Chapters 7 and 10*
67. Decay heat	*Chapters 4 and 10*
68. Radiation shielding	*Chapters 9, 10, and 12*
69. Protection against radioactive release	*Chapters 5, 9, 10, and 12*

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-9

AEC GENERAL DESIGN CRITERIA - GROUP IX PLANT EFFLUENTS

Criterion	*Conformance*[a]
70. Release control of radioactivity to the environment	*Chapters 1, 5, 7, 9, and 14*

a. Referenced to HNP-1-FSAR chapters and appendices.

TABLE F.2-10

ENGINEERED SAFETY FEATURE SYSTEMS

- *Containment Systems*
  - *Containment Heat Removal*
  - *Combustible Gas Control*
  - *Containment Isolation*

- *Emergency Core Cooling System*
  - *HPCI*
  - *ADS*
  - *CS*
  - *LPCI*

- *Standby Gas Treatment System*
- *MCR Habitability System*
- *MSIV - LCS*
- *Control Rod Velocity Limiter*
- *Control Rod Drive Housing Support*
- *Main Steam Line Flow Restrictors*
- *Main Steam Line Isolation Valves*

F.3 EVALUATION WITH RESPECT TO 1971 GENERAL DESIGN CRITERIA

A design evaluation of each criterion based on the current understanding of the intent of the "General Design Criteria for Nuclear Power Plants," effective May 21, 1971, and subsequently amended July 7, 1971, is included in the following pages.

Criterion 1 - Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to meet quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified, as necessary, to assure a quality product in keeping with the required safety function. A quality assurance (QA) program shall be established and implemented to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Design Evaluation

Structures, systems, and components important to safety, outlined in Appendix A of the Georgia Power Company (GPC) QA Manual, are designed, fabricated, erected, and tested under a QA program satisfying the intent of Appendix B of 10 CFR 50. As described in appendix D of this document, the GPC QA Program is designed and organized to assure that the Hatch Nuclear Plant (HNP) is designed, fabricated, and constructed in conformance with the regulatory requirements and design bases outlined in the license application.

Design requirements and other information regarding implementation of the QA program are described in various Final Safety Analysis Report (FSAR) sections. Codes and standards applying to safety-related pressure-retaining piping and equipment are included in appendix A; building codes and standards are listed in chapter 12; and detailed seismic requirements are outlined in appendix C.

Structures, systems, and components are first classified with regard to location, service, and relationship to the safety function to be performed. Recognized codes and standards are applied to the equipment in accordance with the appropriate classification. Where codes are not available or where the existing code must be modified, a rigorous justification is provided in the FSAR.

Documents and records proving that the requirements of the QA program have been satisfied are required. The documentation shows that the required codes, standards, and specifications were observed, that specified materials were used, that correct procedures were utilized, that qualified personnel performed the work, and that inspections and tests verify that finished parts and components meet the applicable specifications. All applicable records are maintained during the operational life-of-the-plant and are readily available for reference.

The QA program developed by the applicant and contractors satisfies the requirements of criterion 1.

For further discussion, refer to the following FSAR sections:

• *Plant Description*	*1.6*
• *Quality Assurance Program*	*1.10*
• *Fuel Mechanical Design*	*HNP-2, 4.2*
• *Reactivity Control Mechanical Design*	*HNP-2, 4.2*
• *Control Rod Drive Housing Supports*	*HNP-2, 4.5*
• *Nuclear Design*	*HNP-2, 4.3*
• *Thermal and Hydraulic Design*	*HNP-2, 4.4*
• *Reactor Vessel and Appurtenances Mechanical Design*	*4.2*
• *Reactor Recirculation System*	*4.3*
• *Pressure Relief System*	*4.4*
• *Main Steam Line Flow Restrictor*	*4.5*
• *Main Steam Line Isolation Valves*	*4.6*
• *Reactor Core Isolation Cooling System*	*4.7*
• *Residual Heat Removal System*	*4.8*
• *Containment Systems*	*5.0*
• *Emergency Core Cooling System*	*6.0*
• *Reactor Protection System*	*7.2*
• *Primary Containment and Reactor Vessel Isolation Control System*	*7.3*
• *Emergency Core Cooling System Control and Instrumentation*	*7.4*
• *Neutron Monitoring System*	*7.5*
• *Electrical Power Systems*	*8.0*
• *Structures and Shielding*	*12.0*

- *Pressure Integrity of Piping and Equipment Pressure Parts* — *Appendix A*
- *NSSS Equipment Loading Design* — *Appendix C*
- *Quality Assurance Program* — *Appendix D*

Criterion 2 - Design Bases for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effect of natural phenomena, such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches, without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect:

- *Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated.*
- *Appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena.*
- *Importance of the safety functions to be performed.*

Design Evaluation

Structures, systems, and components important to safety have been designed to withstand postulated natural phenomena without loss of capability to perform their safety functions. The design bases for safety-related structures with regard to postulated natural phenomena are discussed in subsections 12.3.3 and 12.3.4.

The most severe natural phenomena that have been reported for the site and surrounding area (with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated) have been used to establish the design bases for safety-related structures, systems, and components. The selection of design basis environmental events is discussed in subsection 12.3.4 and sections 2.4 and 2.5.

Appropriate combinations of normal operational and accident loadings and loadings due to potential natural phenomena have been considered in the design of safety-related structures, systems, and components as outlined section 12.4.

Criterion 3 - Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used whenever practical throughout HNP-2, particularly in locations such as the containment and the control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse *effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.*

Design Evaluation

The Hatch Nuclear Plant is designed to minimize the probability and effect of fires and explosions. Consistent with defense-in-depth philosophy, noncombustible and heat-resistant materials are used in the containment, control room, rooms where safety-related equipment is located, and wherever required throughout the plant.

Appropriate equipment and facilities are provided to protect personnel and equipment from the effects of fire, explosion, and resulting release of toxic vapors. Fire protection features include considerations for hazard containment within a limited area in addition to smoke and/or heat detection systems, water spray systems, water sprinkler systems, carbon dioxide systems, manual base stations, and portable extinguishers.

Fire protection features and systems are engineered to assure that their rupture or inadvertent operation will not significantly impair the capability of safety-related equipment or systems to perform prescribed tasks. All fire protection equipment is accessible for periodic testing and/or inspection. The fire protection systems are reliable, partially automatic units that are engineered and installed in accordance with selected sections of the National Fire Protection Association Codes, the requirements of Nuclear Mutual Property Loss and Prevention Standards, and the Occupational Safety and Health Act.

Detailed information concerning the specific attention afforded the overall plant fire protection program to minimize the probability and consequences of postulated fires is presented in the Edwin I. Hatch Nuclear Plant Units 1 and 2 Fire Hazards Analysis and Fire Protection Program submitted to the Nuclear Regulatory Commission on July 22, 1986. This document also demonstrates compliance of the fire protection program with Design Criterion 5 and BTP-9.5-1, Appendix A.

Criterion 4 - Environmental and Missile Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents (LOCAs). These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Design Evaluation

Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including the design basis LOCA. These structures, systems, and components are appropriately protected against dynamic effects and discharging fluids that may result from equipment failures. Normal and postulated accident effects and load combinations are given in chapter 12 and in appendix A.

Special attention has been directed to the effects of pipe movement, jet forces, and missiles within the primary containment. Pipe whip restraints have been provided to the extent practical. Primary containment integrity protection is discussed in paragraph 5.2.4.6. The structures, systems, and components important to safety have been protected from dynamic effects by separating redundant counterparts such that no single event can prevent a required safety action. These components have been located and routed to avoid potentially hazardous areas to the extent practical. The means used to preserve the independence of redundant counterparts of safety-related systems is discussed in chapters 4, 5, 6, 7, and 8.

Dynamic effects external to the plant that are induced by natural phenomena, e.g., tornado-produced missiles, have been appropriately considered in section 12.3.

Criterion 5 - Sharing of Structures, Systems, and Components

Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform safety functions, including (in the event of an accident in one unit) an orderly shutdown and cooldown of the remaining units.

Design Evaluation

HNP-1 and HNP-2 share the facilities and equipment listed below. Reactor safety is not impaired by sharing these facilities and equipment (subsection 1.12.2).

- *Shared facilities.*
  - *Main stack.*
  - *Intake structure.*
  - *Diesel generator building.*
  - *Control building. (The control panels are separate; the units are controlled separately.)*
  - *Refueling floor of reactor building.*
  - *Service building.*
  - *Water treatment building.*
  - *Fire protection pumphouse.*

  - *Waste gas treatment building.*
  - *Discharge pipe.*
  - *Switchyard.*
  - *Warehouse.*
  - *Security buildings.*

- *Shared Equipment.*
  - *One standby ac power supply.*
  - *Fuel pool cooling and cleanup system.*
  - *Security system.*
  - *Fire protection system.*
  - *Makeup water treatment system.*
  - *Potable and sanitary water system.*
  - *Plant communication system.*
  - *Main control room environmental control system.*
  - *Main stack radiation monitoring system.*
  - *Turbine building cranes.*
  - *Reactor building refueling floor crane.*

Criterion 10 - Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel-design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Design Evaluation

The reactor core components consist of fuel assemblies, control rods, incore ion chambers, neutron sources, and related items. The mechanical design is based on conservative application of stress limits, operating experience, and experimental test results. The fuel is designed to provide high integrity over a complete range of power levels including transient conditions.

The core is sized with sufficient heat transfer area and coolant flow to ensure that there is no fuel damage under normal conditions or anticipated operational occurrences (AOOs).

The reactor protection system (RPS) is designed to monitor certain reactor parameters, sense abnormalities, and scram the reactor, thereby preventing fuel damage when trip points are exceeded. The scram trip setpoints were developed using the criteria of Regulatory Guide 1.105, taking into consideration instrument loop uncertainties and the analytical limit. The analytical limits are the values used as inputs to the safety analysis. In cases where certain process values were not used as inputs to the safety analysis, the analytical limits were not available and operating experience and historical data were justified and used. There is no case in which the scram trip setpoints allow the core to exceed the thermal-hydraulic safety limits. Power for the RPS is supplied by its own high-inertia ac motor-generator sets. Alternate electrical power is available to the RPS buses.

An analysis and evaluation of the effects upon core fuel following adverse plant operating conditions were performed. The results of AOOs are presented in HNP-2-FSAR section 15.2 and show that the minimum critical power ratio (MCPR) is always greater than Technical Specifications values, thereby assuring adequate fuel protection.

The reactor core and associated coolant, control, and protection systems are designed to assure that the specified fuel-design limits are not exceeded during conditions of normal or abnormal operation and, therefore, meet the requirements of criterion 10.

For further discussion, see the following FSAR sections:

- *Plant Description* — *1.6*
- *Fuel Mechanical Design* — *HNP-2, 4.2*
- *Nuclear Design* — *HNP-2, 4.3*
- *Thermal and Hydraulic Design* — *HNP-2, 4.4*
- *Control Rod Drive Housing Supports* — *HNP-2, 4.5*
- *Reactor Recirculation System* — *4.3*
- *Reactor Core Isolation Cooling System* — *4.7*
- *Residual Heat Removal System* — *4.8*
- *Reactor Protection System* — *7.2*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 11 - Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that, in the power operating range, the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Design Evaluation

The reactor core is designed to have a reactivity response that regulates or damps changes in power level and spatial distributions of power production to a level consistent with safe and efficient operation.

The inherent dynamic behavior of the core is characterized in terms of:

- *Fuel temperature of the Doppler coefficient.*
- *Moderator void coefficient.*
- *Moderator temperature coefficient.*

The combined effect of these coefficients in the power range is termed the power coefficient.

Doppler reactivity feedback occurs simultaneously with a change in fuel temperature, opposes the power change that caused it, and contributes to system stability. Since the Doppler reactivity opposes load changes, it is desirable to maintain a large ratio of moderator void coefficient to Doppler coefficient for optimum load following capability. The boiling water reactor (BWR) has an inherently large moderator-to-Doppler coefficient ratio permitting the use of coolant flowrate for load following.

The removal of any single control rod from a normal pattern results in a reactivity insertion which is counteracted by the reactivity effects of the fuel Doppler coefficient and the moderator coefficients referred to above.

In a BWR, the moderator void coefficient is of primary importance during operation at power. Nuclear design is based on the void coefficient inside the fuel channel being negative. The negative void reactivity coefficient provides an inherent negative feedback during power transients. Because of the large negative moderator coefficients of reactivity, the BWR has a number of inherent advantages, such as:

- *Use of coolant flow as opposed to control rods for load following.*
- *Inherent self flattening of the radial power distribution.*
- *Ease of control.*
- *Spatial xenon stability.*

The reactor is designed so that the moderator temperature coefficient is small and positive in the cold condition; however, the overall power reactivity coefficient is negative.

The reactor core and associated coolant system, which is in the power operating range, is designed so that prompt, inherent dynamic behavior tends to compensate for any rapid increase in reactivity. This is in accordance with criterion 11.

For further discussion, see the following FSAR sections:

•	*Nuclear Design.*	*HNP-2, 4.3*
•	*Thermal and Hydraulic Design.*	*HNP-2, 4.4*
•	*Nuclear System Stability Analysis.*	*7.15*

Criterion 12 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations resulting in conditions exceeding specified acceptable fuel-design limits are not possible or can be reliably and readily detected and suppressed.

Design Evaluation

The reactor core is designed to ensure that no power oscillation will cause fuel-design limits to be exceeded. The power reactivity coefficient is the composite simultaneous effect of the fuel temperature or Doppler coefficient, moderator void coefficient, and moderator temperature coefficient to the change in power level. The power reactivity coefficient is negative and well within the range required for adequate damping of power and spatial xenon disturbances. Analytical studies indicate that for BWRs, under-damped, unacceptable power distribution behavior could only be expected to occur with power coefficients $> \sim -0.01\ (\Delta k/k)/(\Delta P/P)$*. Operating experience has shown large BWRs to be inherently stable against xenon-induced power instability.*

The large, negative operating coefficients provide:

- *Good load following with well damped behavior and little undershoot or overshoot in the heat transfer response.*
- *Load following with recirculation flow control.*
- *Strong damping of spatial power disturbances.*

The RPS design provides protection from excessive fuel-cladding temperatures and protects the nuclear system process barrier from excessive pressures which threaten the integrity of the system. Local abnormalities are sensed and, if protection system limits are reached, corrective action is initiated through an automatic scram. High integrity of the protection system is achieved through the combination of logic arrangement, trip channel redundancy, power supply redundancy, and physical separation.

The reactor core and associated coolant, control, and protection systems are designed to suppress any power oscillations which could result in exceeding fuel-design limits. These systems assure that criterion 12 is met.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Nuclear Design* — *HNP-2, 4.3*
- *Thermal and Hydraulic Design* — *HNP-2, 4.4*
- *Pressure Relief System* — *4.4*
- *Reactor Protection System* — *7.2*
- *Reactor Manual Control System* — *7.7*
- *Nuclear System Stability Analysis* — *7.15*
- *Analyses of Anticipated Operational Occurrences* — *HNP-2, 15.2*

Criterion 13 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Design Evaluation

The fission process is monitored and controlled for all conditions from source range through power operating range. The neutron monitoring system (NMS) detects core conditions that threaten the overall integrity of the fuel barrier due to excess power generation and also provides a signal to the RPS. Fission counters and ion chambers located in the core are used for the source range through the power operating range. The detectors are located to provide maximum sensitivity to control rod movement during startup and to provide optimum monitoring in the intermediate and power ranges.

The source range monitor subsystem (SRMS) provides neutron flux information during reactor startup and low flux level operations. Detectors are inserted into the core for a reactor startup and may be withdrawn after neutron flux is indicated on the intermediate range monitor subsystem (IRMS). The SRMS can provide detection of < a 20-s period under the worst possible startup conditions and is capable of generating a trip signal to block rod withdrawal.

The IRMS monitors neutron flux from the upper portion of the SRMS to the lower portion of the average power range monitor subsystem (APRMS). The IRMS is capable of generating a trip signal to block rod withdrawal or to scram the reactor.

The local power range monitor subsystem (LPRMS) consists of fission chambers located through the core, signal conditioning equipment, and trip functions. LPRMS signals are also used in the APRMS, rod block monitor subsystem (RBMS), and process computer. The RBMS is designed to prevent local fuel damage as a result of a single rod withdrawal starting with local power at operating limits. The trip setting is flow referenced to reduce the trip level as required by reduced flow.

The traversing incore probe (TIP) subsystem provides a signal proportional to the axial neutron flux distribution of the core. This system is used in the calibration of the LPRMS and the evaluation of MCPR and overall peaking factors.

The RPS protects the fuel barriers and the nuclear process barrier by monitoring plant parameters and causing a reactor scram when predetermined setpoints are exceeded.

The reactor manual control system (RMCS) consists of the electrical circuitry, switches, indicators, and alarm devices required to provide for the manipulation of the control rods and surveillance equipment. Separation of the scram and normal rod control function prevents failures in the RMCS circuitry from affecting the scram circuitry.

Reactor vessel instrumentation monitors the transient reactor vessel process temperatures, water levels, water flow, internal pressure, and water leakage detection from the top head flange. This information is used to assess conditions existing inside the vessel and the physical condition of the reactor vessel. Reactor vessel temperatures are recorded on a multipoint recorder in the control room. Controlled heating and cooling rates allow thermal stress to be appropriately limited. Reactor vessel water level is also indicated in the control room. Recirculation loop flow, core flow, and differential pressure between the reactor vessel annulus outside of the core and the core inlet plenum are indicated in the control room.

To provide protection against the consequences of accidents involving the release of radioactive materials from the fuel and nuclear system process barrier, the primary containment and reactor vessel isolation control system initiates automatic isolation of appropriate pipelines penetrating the primary containment whenever monitored variables exceed preselected operational limits. (See responses to criteria 55 and 56.)

Nuclear system leakage limits are established so that appropriate action can be taken to ensure the integrity of the nuclear system process barrier. Nuclear system leakage rates are classified as "identified" and "unidentified" which corresponds respectively to the flow to the equipment drain and drywell floor drain sumps. The permissible total leakage rate limit to these sumps is based upon the makeup capabilities of various reactor component systems. A flow integrator and recorders are used to determine the leakage flow pumped from the drain sumps. The unidentified leakage rate is limited to 15 gal/min. This is significantly less than the value that has been conservatively calculated to be minimum leakage from a crack large enough to propagate rapidly but which still allows time for identification and corrective action before integrity of the process barrier is threatened.

A process computer system receives input from plant variables, including all variables of the RPS. The inputs are scanned and monitored for change of state and provide a quick and accurate determination of *the core thermal performance. Certain inputs are annunciated to aid in general plant operation. The process computer system provides inputs to the rod block circuitry. The data reduction, accounting, and logging functions supplement procedural requirements for control rod manipulation during reactor startup and shutdown. Although the process computer is a valuable aid to the operator, it is not required for the safe operation of the plant.*

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Main Steam Line Isolation Valves* — *4.6*
- *Nuclear System Leakage Detection and Leakage Rate Limits* — *4.10*
- *Containment Systems* — *5.0*
- *Reactor Protection System* — *7.2*
- *Primary Containment and Reactor Vessel Isolation Control System* — *7.3*
- *Neutron Monitoring System* — *7.5*
- *Reactor Manual Control System* — *7.7*
- *Reactor Vessel Instrumentation* — *7.8*
- *Recirculation Flow Control System* — *7.9*
- *Process Computer System* — *7.14*

<u>*Criterion 14 - Reactor Coolant Pressure Boundary*</u>

The RCPB shall be designed, fabricated, erected, and tested to have an extremely low probability of abnormal leakage, rapidly propagating failure, and gross rupture.

Design Evaluation

The piping and equipment pressure parts within the RCPB through the outer isolation valve are designed, fabricated, erected, and tested to provide a high degree of integrity throughout the life of the plant. Appendix A classifies the systems and components within the RCPB as Code Group A. The design requirements and codes and the standards applied to this code group ensure a quality product in accordance with the safety functions to be performed.

To minimize the possibility of brittle fracture within the RCPB, the fracture or notch properties and the operating temperature of ferritic materials are controlled to ensure adequate toughness when the system is pressurized to more than 20% of the design pressure. Section 4.2 describes the methods used to control notch toughness properties by selecting and testing fine grained steels and limiting neutron *exposure of materials to acceptable levels. Materials to be impact tested are tested by the Charpy V-notch method in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III. By maintaining a material service temperature of at least 60°F above the nil ductility transition temperature (NDTT) for the RCPB, adequate protection is further assured. Where RCPB piping penetrates the containment, the fracture toughness temperature requirements of the RCPB materials apply.*

Piping and equipment pressure parts of the RCPB are assembled and erected by welding unless applicable codes permit flanged or screwed joints. Welding procedures are employed which produce welds of complete penetration and complete fusion, in addition to welds that are free of unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section IX. Qualification records, including the results of procedure and performance qualification tests and identification symbols assigned to each welder, are maintained.

Appendix A contains the detailed material and examination requirements for the piping and equipment of the RCPB prior to and after its assembly and erection. Leakage testing and surveillance are accomplished as described in the evaluation against criterion 30.

The design, fabrication, erection, and testing of the RCPB assure an extremely low probability of failure or abnormal leakage, thus satisfying the requirements of criterion 14.

For further discussion, see the following FSAR sections:

- *Reactor Vessel and Appurtenances Mechanical Design* — *4.2*
- *Reactor Recirculation System* — *4.3*
- *Pressure Relief System* — *4.4*
- *Reactor Vessel Instrumentation* — *7.8*
- *Analyses of Anticipated Operational Occurrences* — *HNP-2, 15.2*
- *Pressure Integrity of Piping and Equipment Pressure Parts* — *Appendix A*
- *NSSS Equipment Loading Design* — *Appendix C*
- *Quality Assurance Program* — *Appendix D*

<u>Criterion 15 - Reactor Coolant System (RCS) Design</u>

The RCS and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Design Evaluation

The RCS consists of the reactor vessel and appurtenances, the reactor recirculation system, the pressure relief system, the main steam lines, the reactor core isolation cooling (RCIC) system, and the residual heat removal (RHR) system. These systems are designed, fabricated, erected, and tested to stringent quality requirements and appropriate codes and standards which assure high integrity of the RCPB throughout the life of the plant. The RCS is designed and fabricated to meet the following minimum requirements:

- *Reactor Vessel - ASME Boiler and Pressure Vessel Code, Section III, Subsection A.*
- *Pumps - ASME Boiler and Pressure Vessel Code, Section III, Subsection C.*
- *Piping and Valves - American National Standards Institute (ANSI) B-31.1.0, Code for Pressure Power Piping.*

The auxiliary, control, and protection systems associated with the RCS provide sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences. As described in the evaluation of criterion 13, instrumentation is provided to monitor essential variables to ensure that they are within prescribed operating limits. If the monitored variables exceed their predetermined settings, the auxiliary, control, and protection systems automatically respond to maintain the variables and systems within allowable design limits.

An example of the integrated protective action scheme which provides sufficient margin to assure that the design conditions of the RCPB are not exceeded is the automatic initiation of the pressure relief system upon receipt of an overpressure signal. To accomplish overpressure protection, a number of pressure-operated relief valves are provided that can discharge steam from the nuclear system to the pressure suppression pool. The pressure relief system also provides for automatic depressurization of the nuclear system in the event of a LOCA in which the vessel is not depressurized by the accident. The depressurization of the nuclear system in this situation allows operation of the emergency core cooling system (ECCS) to supply enough cooling water to adequately cool the core. In a similar manner, other auxiliary, control, and protection systems provide assurance that the design conditions of the RCPB are not exceeded during any conditions of normal operation, including AOOs.

The application of appropriate codes and standards and high quality requirements for the RCS, in addition to the design features of its associated auxiliary, control, and protection systems, assure that the requirements of criterion 15 are satisfied.

For further discussion, see the following FSAR sections:

• *Reactor Vessel and Appurtenances Mechanical Design*	*4.2*
• *Reactor Recirculation System*	*4.3*
• *Pressure Relief System*	*4.4*
• *Nuclear System Leakage Detection and Leakage Rate Limits*	*4.10*
• *Reactor Vessel Instrumentation*	*7.8*
• *Analyses of Anticipated Operational Occurrences*	*HNP-2, 15.2*
• *Pressure Integrity of Piping and Equipment Pressure Parts*	*Appendix A*
• *NSSS Equipment Loading Design*	*Appendix C*

Criterion 16 - Containment Design

Reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions important to safety are not exceeded for the time duration required for postulated accident conditions.

Design Evaluation

The reactor is housed within a drywell containment vessel made of steel plates 3/4-in. to 2 9/16-in. thick. Reinforced concrete ranging in thickness from 5 ft 7 in. to 10 ft is placed around the drywell vessel. The ability of the containment vessel to provide a leaktight barrier against uncontrolled release of radioactivity is verified by a preoperational leakage test and during the life of the plant. Additional descriptions of the primary containment are found in section 5.2 and appendix K.

To prevent the containment design conditions important to safety from being exceeded, the containment is provided with the following:

- *Pressure suppression chamber and vent system by which steam escaping into the drywell is condensed through contact with a supply of stored water (section 5.2).*
- *Cooling systems to remove heat from the water in the suppression pool (section 4.8).*
- *Drywell and suppression chamber water spraying systems to condense steam in the drywell and to cool noncondensable gases in the suppression chamber (section 4.8).*

A description of the primary containment response to the postulated design basis LOCA is provided in HNP-2-FSAR paragraph 6.2.1.4.2.

Criterion 17 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall provide sufficient capacity and capability to assure the following:

- *A. Specified acceptable fuel-design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences.*

- *B. The core is cooled, and containment integrity and other vital functions are maintained in the event of postulated accidents.*

The onsite electric power supplies, including the batteries, and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located to minimize to the extent practical the likelihood of simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time, following a loss of all onsite ac power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel-design limits and design conditions of the RCPB are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Design Evaluation

Both onsite and offsite electric power systems are capable of providing a reliable source of power to permit functioning of structures, systems, and components important to safety. Both of these sources have the capability to furnish required power for all postulated AOO and accident conditions (chapter 8).

In the event that all offsite circuits are lost, the emergency buses will be connected to the onsite emergency diesel generators.

Onsite power ac source capacity and design bases are discussed in section 8.4. The onsite electric power system has sufficient independence, redundancy, and testability to perform its safety function assuming a single failure. Each diesel generator has its own battery; there are two separate plant batteries for HNP-1 as discussed in section 8.5.

Physically independent circuits are provided from the HNP-1 switchyard to the startup auxiliary transformers. These circuits are fed by at least two independent transmission lines, physically separated as they approach the switchyard so that the failure of one line will not cause failure of the other. From the switchyard to the onsite electrical distribution system, separation is also provided so that failure of one circuit will not cause the failure of the other.

Each incoming transmission line is normally connected to the switchyard except during short maintenance periods. One or more of these lines is continually connected to a startup transformer to supply power immediately to the emergency 4160-V buses in the event of a LOCA. In the event of failure of the normal source, the emergency 4160-V buses will be energized by automatic transfer to the other dedicated startup transformer (section 8.3).

A switching scheme offering maximum flexibility for both maintenance and operation in that breakers can be removed from service for maintenance without removing the associated line or transformer from service is used. Components associated with the relaying system are connected so that each protective function is redundant, thus meeting the single-failure criterion (subsection 8.2.3).

<u>*Criterion 18 - Inspection and Testing of Electric Power Systems*</u>

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, e.g., wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to periodically test the following:

- *Operability and functional performance of the systems' components, such as onsite power sources, relays, switches, and buses.*

- *Operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.*

Design Evaluation

The primary circuit breakers are inspected, maintained, and tested on a routine basis. This can be accomplished without removing the generators, transformers, and transmission lines from service.

Transmission line protective relaying is tested on a routine basis. This can be accomplished without removing the transmission lines from service. Generator, unit auxiliary transformer, and startup auxiliary transformer relaying are tested during refueling. Automatic transfers of 4160-V buses 1E, 1F, and 1G from startup transformers to emergency standby diesel generators are tested during the refueling of the unit to prove the operability of the system.

The 4160- and 600-V circuit breakers and associated equipment may be tested while individual equipment is shutdown. The circuit breakers may be placed in the "test" position and tested functionally. Breaker opening and closing may also be exercised. Circuit breakers and contactors for redundant or duplicated circuits may be tested while in service without interfering with the operation of the plant.

The dc system is equipped with detectors to indicate when there is a ground existing on any portion of the system. A ground on one portion of the dc system will not cause any equipment to malfunction. The batteries are under continuous automatic charging and are inspected and checked on a routine basis while the unit is in service.

To verify that the emergency power system will properly respond within the required time limit, when required, the following typical tests are periodically performed:

A. *Manual initiation of the ability of the diesel generators to start and deliver power up to the nameplate rating when operating in parallel with normal power sources is demonstrated. Normal plant operation will not be affected. The duration of the test is long enough for the diesels to reach equilibrium operating temperatures.*

B. *Manual initiation of permanently installed testing devices demonstrates the ability of the control system to automatically start the diesel generator and restore power to vital equipment by simulating a loss-of-offsite power (LOSP) and/or LOCA.*

These tests include:

- *Test for automatic transfer of emergency buses being supplied by the normal offsite power source to the alternate offsite power source.*
- *Test for automatically starting, connecting the diesel generators to the emergency bus, and loading the diesel generators upon LOSP sources.*
- *Test for automatically starting diesel generators upon a LOCA signal.*
- *Test for automatically starting, connecting diesel generators to the emergency buses, and sequentially loading the diesel generators upon a LOCA signal accompanied by a LOSP signal.*

The capability to perform the above tests complies with the intent of criterion 18.

<u>*Criterion 19 - Control Room*</u>

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including LOCAs. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided with:

- *A design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown.*

- *A potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.*

Design Evaluation

A control room is provided in which appropriate controls and instrumentation are located to permit personnel to safely operate the unit under normal conditions or maintain it in a safe condition under accident conditions. The radiation protection afforded control room personnel permits the required habitability discussed in section 12.7.

The ability to provide for prompt hot shutdown of the reactor and the potential capability for subsequent cold shutdown through the use of suitable procedures from locations outside the control room is presented in HNP-2-FSAR section 15.4.

<u>Criterion 20 - Protection System Functions</u>

The protection system shall be designed to:

- *Automatically initiate the operation of appropriate systems, including the reactivity control systems, to assure that specified acceptable fuel-design limits are not exceeded as a result of anticipated operational occurrence.*

- *Sense accident conditions and initiate the operation of systems and components important to safety.*

Design Evaluation

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and nuclear system process barrier. Fuel damage is prevented by initiation of an automatic reactor shutdown if monitored nuclear system variables exceed preestablished limits of AOOs. Scram trip settings are selected and verified to be far enough above or below operating levels to provide proper protection but not be subject to spurious scrams. The RPS includes the motor-generator power system, sensors, relays, bypass circuitry, and switches that signal the control rod system to scram and shut down the reactor. The scrams initiated by NMS variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and reactor vessel low water level will prevent fuel damage following AOOs. Specifically, these process parameters initiate a scram in time to prevent the core from exceeding thermal-hydraulic safety limits during AOOs. Response by the RPS is prompt and the total scram time is short. Control rod scram motion starts ~ 200 ms after the high-flux setpoint is exceeded.

In addition to the RPS which provides for automatic shutdown of the reactor to prevent fuel damage, protection systems are provided to sense accident conditions and automatically initiate the operation of other systems and components important to safety. Systems such as the ECCS are automatically initiated to limit the extent of fuel damage following a LOCA. Other systems automatically isolate the reactor *vessel or the primary containment to limit the extent of fuel damage following a postulated LOCA and prevent the release of significant amounts of radioactive material from the fuel and the nuclear system process barrier. The controls and instrumentation for the ECCS and the isolation systems are automatically initiated when monitored variables exceed preselected operational limits.*

The design of the protection system satisfies the functional requirements as specified in criterion 20.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Control Rod Drive Housing Supports* — *HNP-2, 4.5*
- *Pressure Relief System* — *4.4*
- *Main Steam Line Isolation Valves* — *4.6*
- *Emergency Core Cooling System* — *6.0*
- *Reactor Protection System* — *7.2*
- *Primary Containment and Reactor Vessel Isolation Control System* — *7.3*
- *Emergency Core Cooling System Control and Instrumentation* — *7.4*
- *Neutron Monitoring System* — *7.5*
- *Process Radiation Monitoring* — *7.12*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 21 - Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure the following:

A. *No single failure results in loss of the protection function.*

B. *Removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of the protection system operation can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including capability to test channels independently to determine failures and losses of redundancy that may have occurred.*

Design Evaluation

RPS design fulfills single-failure criteria by providing redundant channels. No single component failure, intentional bypass maintenance operation, calibration operation, or test to verify operational availability will impair the ability of the system to perform its intended safety function. Additionally, the system design assures that when a scram trip point is exceeded there is a high scram probability. However, should a scram not occur, other monitored components will scram the reactor if their trip points are exceeded. There is sufficient electrical and physical separation between channels and between trip logics monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability of the system to respond correctly.

The RPS includes design features that permit inservice testing. This ensures the functional reliability of the system should the reactor variable exceed the corrective action setpoint.

The RPS initiates an automatic reactor shutdown if the monitored plant variables exceed preestablished limits. The protection system consists of two separately powered trip systems. Each trip system has three trip logics, two of which produce an automatic trip signal. The remaining logic is used for a manual trip signal. To produce a scram, at least one logic from each trip system must be tripped. The overall logic scheme is a one-out-of-two-taken-twice arrangement.

The RPS can be tested during reactor operation. Manual scram testing is performed by operating the two manual scram controls, thereby testing one trip system. The total test verifies the ability to deenergize the scram pilot valve solenoids. Indicating lights verify that the actuator contacts have opened. This capability for a thorough testing program significantly increases reliability.

Control rod drive (CRD) operability can be tested during normal reactor operation. Drive position indicators and the incore neutron detectors are used to verify control rod movement. Each control rod can be withdrawn one notch and then reinserted to the original position without significantly perturbing the reactor system. One control rod is tested at a time. Control rod mechanism overdrive demonstrates rod-to-drive coupling integrity. Hydraulic supply subsystem pressures can be observed on control room instrumentation. More importantly, the hydraulic control unit (HCU) scram accumulator and the scram discharge volume level are continuously monitored.

The main steam isolation valves (MSIVs) may be tested during full reactor operation. They can be closed to 90% of full-open position without affecting the reactor operation. If reactor power is reduced to 75% of full power, an isolation valve may be fully closed. Provisions are provided to evaluate valve stem leakage during reactor shutdown. During refueling operation, valve leakage rates can be determined.

RHR system testing can be performed during normal operation. Main system pumps can be evaluated by taking suction from the suppression pool. System design and operating procedures also permit testing the discharge valves to the reactor recirculation loops and the discharge valves to the containment spray headers. The low-pressure coolant injection (LPCI) mode can be tested after reactor shutdown. Each active component of the ECCS which operates in a design basis accident is designed to be operable for test purposes during normal operation of the nuclear system.

The high functional reliability, redundancy, and inservice testability of the protection system satisfy the requirements specified in criterion 21.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Main Steam Isolation Valves* — *4.6*
- *Residual Heat Removal System* — *4.8*
- *Containment* — *5.0*
- *Emergency Core Cooling System* — *6.0*
- *Reactor Protection System* — *7.2*
- *Primary Containment and Reactor Vessel Isolation Control System* — *7.3*
- *Emergency Core Cooling System Control and Instrumentation* — *7.4*
- *Neutron Monitoring System* — *7.5*
- *Process Radiation Monitoring* — *7.12*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 22 - Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Design Evaluation

The components of the protection system are designed so that the mechanical and thermal environment resulting from any emergency situation in which the components are required to function will not interfere with that function. Wiring for the RPS outside of the control room enclosures is run in rigid metallic conduits or raceways segregated from all other wiring. The wires from duplicate sensors on a common process tap are run in separate conduits. The system sensors are electrically and physically separated. Only one trip actuator logic circuit from each trip system may be run in the same conduit or raceway.

The RPS is designed to permit maintenance and diagnostic work while the reactor is operating without restricting the plant operation or hindering the output of any safety functions. The flexibility in design embodied in the protection system allows operational system testing by the use of an independent trip channel for each trip logic input. When an essential monitored variable exceeds its scram trip point, it is sensed by at least two independent sensors in each trip system. An intentional bypass, maintenance operation, calibration operation, or test will result in a single-channel trip. This leaves at least two trip channels per monitored variable capable of initiating a scram. Only one trip channel in each trip system must trip to initiate a scram. Thus, the arrangement of two trip channels per trip system assures that a scram will occur if a monitored variable exceeds its scram setting.

Each CRD mechanism has its own scram and pilot valves; thus, only one drive can be affected if a scram valve fails to open. Two pilot valves are provided for each drive. Both pilot valves must be vented to initiate a scram.

Two MSIVs provide redundancy in each line so that either can perform the isolation function, and can be tested for leakage after the other is closed. The inside valve and the outside valve, in addition to their respective control systems, are physically separated.

The RHR system pumps, motors, piping, and heat exchangers are designed with sufficient redundancy so that only a highly improbable combination of events could result in its inability to provide adequate cooling in each operating mode.

The protection system meets the design requirements for functional and physical independence as specified in criterion 22.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Main Steam Isolation Valves* — *4.6*
- *Residual Heat Removal System* — *4.8*
- *Emergency Core Cooling System* — *6.0*
- *Reactor Protection System* — *7.2*

• *Primary Containment and Reactor Vessel Isolation Control System*	*7.3*
• *Emergency Core Cooling System Control and Instrumentation*	*7.4*
• *Neutron Monitoring System*	*7.5*
• *Process Radiation Monitoring*	*7.12*
• *Safety Analysis*	*HNP-2, 15.2*

Criterion 23 - Protection System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy, e.g., electric power, instrument air, or postulated adverse environments (extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Design Evaluation

The RPS is designed to fail into a safe state. Use of an independent trip channel for each trip logic allows the system to sustain any trip channel failure without preventing other sensors monitoring the same variable from initiating a scram. A single sensor or trip channel failure will cause a channel trip. Only one trip channel must trip in each trip system to initiate a scram. Intentional bypass, maintenance operation, calibration operation, or test will result in a single-channel trip. A failure of any one RPS input or subsystem component will produce a trip in one of two channels. This condition is insufficient to produce a reactor scram, but the system is ready to perform its protective function upon another trip.

The environmental conditions in which the instrumentation and equipment of the RPS must operate were considered in establishing the component specifications. Instrumentation specifications for the reactor and turbine building are based on the worst expected ambient conditions in which the instruments must operate.

The two sources of scram energy used to insert each control rod when the reactor is operating are accumulator pressure and reactor vessel pressure. The scram accumulator stores sufficient energy to effect full insertion of a control rod, independent of any other source of energy. At full operating reactor pressure, the accumulator is actually not needed to meet scram time requirements.

For the MSIVs, locally stored energy (compressed air and/or springs) is used to close the valves in each line without relying on the continuity of any variety of electrical power.

The two loops of the RHR system are cross-connected by a single header making it possible to supply either loop from the pumps in the other loop.

The failure modes of the protection system are such that it will fail into a safe state as required by criterion 23.

For further discussion, see the following FSAR sections:

• *Emergency Core Cooling System*	*6.0*
• *Reactor Protection System*	*7.2*
• *Primary Containment and Reactor Vessel Isolation Control System*	*7.3*
• *Neutron Monitoring System*	*7.5*
• *Electrical Power Systems*	*8.0*

Criterion 24 - Separation of Protection and Control Systems

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited to assure that safety is not significantly impaired.

Design Evaluation

There is separation between the RPS and the process systems. Sensors, trip channels, and trip logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system. High scram reliability is designed into the RPS and the HCU for the CRD. The scram signal and mode of operation overrides all other signals.

Primary containment and reactor vessel isolation control systems are designed so that any one failure, maintenance operation, calibration operation, or test to verify operational availability will not impair the functional ability of the isolation control system to respond to essential variables.

Criterion 25 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel-design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Design Evaluation

The RPS provides protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Any monitored variable which exceeds the scram setpoint will initiate an automatic scram not impairing the remaining variables from being monitored, if one channel fails the remaining portions of the RPS function.

The RMCS is designed so that no single failure can negate the effectiveness of a reactor scram. The circuitry for the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. Because each control rod is controlled as an individual unit, a failure that results in energizing any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod.

The most serious rod withdrawal errors are considered to be when the reactor is just subcritical and an out-of-sequence rod is continuously withdrawn. The rod worth minimizer (RWM) prevents the withdrawal of out-of-sequence control rods below the 10% rated power levels.

If such a continuous rod withdrawal were to occur, the increase in fuel temperature subsequent to scram would not be sufficient to exceed acceptable fuel-design limits.

The design of the protection system assures that specified acceptable fuel-design limits are not exceeded for any single malfunction of the reactivity control systems as specified in criterion 25.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Nuclear Design* — *HNP-2, 4.3*
- *Thermal and Hydraulic Design* — *HNP-2, 4.4*
- *Reactor Protection System* — *7.2*
- *Reactor Manual Control System* — *7.7*
- *Plant Safety Analysis* — *HNP-2, 15.0*

Criterion 26 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions,(e.g., stuck rods), specified acceptable fuel-design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure that acceptable fuel-design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Design Evaluation

Two independent reactivity control systems utilizing different design principles are provided. The normal method of reactivity control employs control rod assemblies which contain boron carbide (B_4C) powder, solid boron carbide for the Westinghouse CR 99 control rods or, in the case of the General Electric Duralife and Marathon control rods, a combination of B_4C powder and solid Hafnium. Control of reactivity is operationally provided by a combination of these movable control rods, burnable poisons, and reactor coolant recirculation system flow. These systems accommodate fuel burnup, load changes, and long-term reactivity changes.

Reactor shutdown by the CRD system is sufficiently rapid to prevent exceeding of acceptable fuel-design limits for normal operation and all AOOs. The circuitry for manual insertion or withdrawal of control rods is completely independent of the circuitry for reactor scram. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. Because each control rod is controlled as an individual unit, a failure that results in energizing any of the insert or withdraw solenoid valves can affect only one control rod. Two sources of scram energy, accumulator pressure and reactor vessel pressure, provide needed scram performance over the entire range of reactor pressure; i.e., from operating conditions to cold shutdown.

The design of the control rod system includes an appropriate margin for malfunctions; e.g., stuck rods, in the highly unlikely event that they do occur. Control rod withdrawal sequences and patterns are selected prior to operation to achieve optimum core performance and, simultaneously, low individual rod worths. The RWM prevents rod withdrawals yielding a rod worth greater than permitted by the preselected rod withdrawal pattern. An additional safety design basis of the control rod system requires that the core in its maximum reactivity condition be subcritical with the control rod of the highest worth fully withdrawn and all other rods fully inserted. Because of the carefully planned and regulated rod withdrawal sequence, prompt shutdown of the reactor can be achieved with the insertion of a small number of the many independent control rods. In the event that a reactor scram is necessary, the unlikely occurrence of a limited number of stuck rods will not hinder the capability of the control rod system to render the core subcritical.

A standby liquid control (SLC) system containing neutron absorbing sodium pentaborate solution is the independent backup system. This system has the capability to shut down the reactor from full power and maintain it in a subcritical condition at any time during the core life. The reactivity control provided to reduce reactor power from a rated to a shutdown condition with the control rods withdrawn in the power pattern accounts for the reactivity effects of xenon decay (eliminating steam voids), change in water density due to the reduction in water temperature, the Doppler effect in uranium, the changing of neutron leakage from boiling to cold, and the changing of rod worth as boron, thereby affecting neutron migration length. A shutdown margin of 0.05 ΔK is also included plus a further margin for inadequate mixing of the sodium pentaborate solution.

The redundancy and capabilities of the reactivity control systems for the BWR satisfy the requirements of criterion 26.

For further discussion, see the following FSAR sections:

• *Reactivity Control Mechanical Design*	*HNP-2, 4.2*
• *Standby Liquid Control System*	*HNP-2, 4.2*
• *Reactor Manual Control System*	*7.7*
• *Process Computer System*	*7.14*

Criterion 27 - Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system (ECCS), of reliably controlling reactivity changes to assure that, under postulated accident conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained.

Design Evaluation

There is no credible event applicable to the BWR which requires combined capability of the control rod system and poison additions by the ECCS. The primary reactivity control system for the BWR during postulated accident conditions is the control rod system. Abnormalities are sensed and, if protection system limits are reached, corrective action is initiated through an automatic scram. High integrity of the protection system is achieved through the combination of logic arrangement, trip channel redundancy, and physical separation. High reliability of reactor scram is further achieved by separation of scram and manual control circuitry, individual control units for each control rod, and fail-safe design features built into the CRD system. Response by the RPS is prompt, and the total scram time is short.

In operating the reactor, there is a spectrum of possible control rod worths, depending on the reactor state and on the control rod pattern chosen for operation. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM enforces the withdrawal sequences with the selected pattern.

The reactor core design assists in maintaining the stability of the core under accident conditions as well as during power operation. Reactivity coefficients in the power range that contribute to system stability are:

- *Fuel temperature or Doppler coefficient.*
- *Moderator void coefficient.*
- *Moderator temperature coefficient.*

The overall power reactivity coefficient is negative and provides a strong negative reactivity feedback under severe power transient conditions.

The design of the reactivity control systems assures reliable control of reactivity under postulated accident conditions with appropriate margin for stuck rods. The capability to cool the core is maintained under all postulated accident conditions; thus, criterion 27 is satisfied.

For further discussion, see the following FSAR sections:

• *Reactivity Control Mechanical Design*	*HNP-2, 4.2*
• *Nuclear Design*	*HNP-2, 4.3*
• *Thermal and Hydraulic Design*	*3.7*
• *Reactor Protection System*	*7.2*
• *Reactor Manual Control System*	*7.7*
• *Process Computer System*	*7.14*
• *Safety Analysis*	*HNP-2, 15.0*

Criterion 28 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effect of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding nor sufficiently disturb the core, its support structures, or other reactor pressure vessel (RPV) internals to impair significantly the capability to cool the core. These postulated reactivity accidents include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Design Evaluation

The control rod system design incorporates appropriate limits on the potential amount and rate of reactivity increase. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM prevents withdrawal other than by the preselected rod withdrawal pattern.

The control rod mechanical design incorporates a hydraulic velocity limiter in the control rod preventing rapid rod ejection. This engineered safeguard protects against a high reactivity insertion rate by limiting the control rod velocity.

The safety analysis (HNP-2-FSAR chapter 15) evaluates in detail the postulated reactivity accidents, as well as AOOs. Analyses are included for rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition. The initial conditions, assumptions, calculational models, sequences of events, and anticipated results of each postulated occurrence are covered in detail. The results of these analyses indicate that none of the postulated reactivity transients or accidents result in damage to the RCPB. In addition, the integrity of the core, its support structures, or other RPV *internals is maintained so that the capability to cool the core is not impaired for any of the postulated reactivity accidents described in the safety analysis.*

The design features of the reactivity control system which limit the potential amount and rate of reactivity increase ensure that criterion 28 is satisfied for all postulated reactivity accidents.

For further discussion, see the following FSAR sections:

• *Reactor Vessel Internals Mechanical Design*	*HNP-2, 4.2*
• *Reactivity Control Mechanical Design*	*HNP-2, 4.2*
• *Nuclear Design*	*HNP-2, 4.3*
• *Control Rod Drive Housing Supports*	*HNP-2, 4.5*
• *Reactor Vessel and Appurtenances Mechanical Design*	*4.2*
• *Pressure Relief System*	*4.4*
• *Main Steam Line Flow Restrictor*	*4.5*
• *Main Steam Isolation Valves*	*4.6*
• *Process Computer System*	*7.14*
• *Safety Analysis*	*HNP-2, 15.0*
• *Pressure Integrity of Piping and Equipment Pressure Parts*	*Appendix A*
• *NSSS Equipment Loading Design*	*Appendix C*

Criterion 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Design Evaluation

The high functional reliability of the protection and reactivity control systems is achieved through the combination of logic arrangement, redundancy, physical and electrical independence, functional separation, fail-safe design, and inservice testability. These design features are discussed in detail in criteria 21, 22, 23, 24, and 26.

An extremely high probability of an accurate protection and reactivity control systems response to anticipated operational occurrences is maintained by a thorough program of inservice testing and surveillance. Active components can be tested or removed from service for maintenance during reactor operation without compromising the protection or reactivity control functions even in the event of a subsequent single failure. Components important to safety, such as CRDs, MSIVs, RHR pumps, etc., are tested during normal reactor operation. Functional testing and calibration schedules are developed using available failure rate data, reliability analyses, and operating experience. These schedules represent an optimization of the protection and reactivity control systems' reliability by considering, on one hand, the failure probabilities of individual components and, on the other hand, the reliability effects during individual component testing on the portion of the system not undergoing a test. The capability for inservice testing ensures the high functional reliability of the protection and reactivity control systems should a reactor variable exceed the corrective action setpoint.

The capabilities of the protection and reactivity control systems to perform their safety functions in the event of AOOs are satisfied in agreement with the requirements of criterion 29.

For further discussion, see the following FSAR sections:

- *Reactivity Control Mechanical Design* — *HNP-2, 4.2*
- *Main Steam Isolation Valves* — *4.6*
- *Residual Heat Removal System* — *4.8*
- *Containment Systems* — *5.0*
- *Emergency Core Cooling System* — *6.0*
- *Reactor Protection System* — *7.2*
- *Primary Containment and Reactor Vessel Isolation Control System* — *7.3*
- *Emergency Core Cooling System Control and Instrumentation* — *7.4*
- *Neutron Monitoring System* — *7.5*
- *Process Radiation Monitoring System* — *7.12*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 30 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the reactor coolant leakage source.

Design Evaluation

By utilizing conservative design practices and detailed quality control procedures, the pressure-retaining components of the RCPB are designed and fabricated to retain their integrity during normal and postulated accident conditions. Accordingly, components which comprise the RCPB are designed, fabricated, erected, and tested in accordance with recognized industry codes and standards listed in appendix A. Further, product and process quality planning is provided as (appendix D) to assure conformance with the applicable codes and standards, and to retain appropriate documented evidence verifying compliance. Because the subject matter of this criterion deals with the aspects of the RCPB, further discussion of this subject is treated in the response to criterion 14.

Means are provided for detecting reactor coolant leakage. The leak detection system (LDS) consists of sensors and instruments to detect, annunciate, and in some cases, isolate the RCPB from potential hazardous leaks before predetermined limits are exceeded. Small leaks are detected by temperature and pressure changes, increased frequency of sump pump operation, and by measuring fission product concentration in the primary containment atmosphere. In addition to these means of detection, large leaks are detected by flowrates in process lines and by changes in reactor water level. The allowable leakage rates are based on the predicted and experimentally determined behavior of cracks in pipes, the ability to make up coolant system leakage, the normally expected background leakage due to equipment design, and the detection capability of the various sensors and instruments. The total leakage rate limit is established so that, in the absence of normal ac power concomitant with a loss of feedwater supply, makeup capabilities are provided by the CRD and RCIC systems. While the LDS provides protection from small leaks, the ECCS network provides protection for the complete range of discharges from ruptured pipes. Thus protection is provided for the full spectrum of possible discharges.

The RCPB and the LDS are designed to meet the requirements of criterion 30.

For further discussion, see the following FSAR sections:

- *Reactor Vessel and Appurtenances Mechanical Design* — *4.2*
- *Reactor Recirculation System* — *4.3*
- *Pressure Relief System* — *4.4*
- *Nuclear Steam Leakage Detection and Leakage Rate Limits* — *4.10*
- *Reactor Vessel Instrumentation* — *7.8*
- *Analyses of Anticipated Operational Occurrences* — *HNP-2, 15.2*
- *Pressure Integrity of Piping and Equipment Pressure Parts* — *Appendix A*
- *NSSS Equipment Loading Design* — *Appendix C*
- *Quality Assurance Program* — *Appendix D*

Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The RCPB shall be designed with sufficient margin to assure that, when stressed under operating, maintenance, testing, and postulated accident conditions, the boundary behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions in addition to the uncertainties in determining material properties; the effects of irradiation on material properties; residual, steady-state, and transient stresses; and size of flaws.

Design Evaluation

Brittle fracture control of pressure retaining ferritic materials is provided to ensure protection against nonductile fracture. To minimize the possibility of brittle-fracture failure of the RPV, the following steps have been taken:

A. *The initial ductile brittle transition temperature of materials used in the reactor vessel was known by reference or established empirically.*

B. *Expected shifts in transition temperature during design service life due to neutron flux were determined and employed in the reactor vessel design.*

The NDTT is defined as the temperature below which ferritic steel breaks in a brittle rather than ductile manner. The NDTT increases as a function of neutron exposure at integrated neutron exposures greater than about 1×10^{17} nvt with neutrons having energies in excess of 1 MeV. Since the material NDTT dictates the minimum operating temperature at which the reactor vessel can be pressurized, it is desirable to keep the NDTT as low as possible.

The reactor assembly design provides an annular space from the outermost fuel assemblies to the inner surface of the reactor vessel that serves to attenuate the fast neutron flux incident upon the reactor vessel wall. This annular volume contains the core shroud, jet pump assemblies, and reactor coolant. The RCPB is designed, maintained, and tested such that adequate assurance is provided that the boundary will behave in a nonbrittle manner throughout the life of the plant. Therefore, the RCPB is in conformance with criterion 31.

For further discussion, see the following FSAR sections:

• *Reactor Vessel and Appurtenances Mechanical Design.*	*4.2*
• *Pressure Integrity of Piping and Equipment Pressure Parts.*	*Appendix A*

Criterion 32 - Inspection of Reactor Coolant Pressure Boundary

Components comprising the RCPB shall be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and an appropriate material surveillance program for the RPV.

Design Evaluation

An access study was initiated in the spring of 1969 to identify those provisions which could be reasonably made in order to approach reasonable compliance with the intent of the October 1968, "Draft ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems." It should be recognized, however, that the contract date of HNP-1 is ~ 1 year prior to the initial publication of the Draft Code, issued for trial use and comment in October 1968. The results of this study were filed February 25, 1970, as post-construction permit supplementary information to the Preliminary Safety Analysis Report (PSAR). This supplementary information describes design features incorporated to provide access and compares this access with that required to comply with the Draft ASME Code. Utilizing these design features, the inservice inspection program for the RCPB was developed by adopting, insofar as practicable, the principles and intent embodied in Section XI of the ASME Boiler and Pressure Vessel Code, "In-Service Inspection of Nuclear Reactor Coolant Systems," dated January 1, 1970. It must be pointed out that HNP-1 was not specifically designed to meet the requirements of Section XI; therefore, 100% compliance is not feasible. The inservice inspection program is described in appendix H.

The reactor recirculation piping and main steam piping are hydrostatically tested with the RPV at a test pressure that is in accordance with Section III of the ASME Code.

Vessel material surveillance samples are located within the RPV to enable periodic monitoring of material properties with exposure. The program includes specimens of the base metal, heat-affected zone within the base metal, and weld metal.

For further discussion, see the following FSAR sections:

- *Reactor Vessel and Appurtenances Mechanical Design* — *4.2*
- *Reactor Recirculation System* — *4.3*
- *Inservice Inspection Program* — *Appendix H*

<u>*Criterion 33 - Reactor Coolant Makeup*</u>

A system to supply reactor coolant makeup for protection against small breaks in the RCPB shall be provided. The system safety function shall be to assure that specified acceptable fuel-design limits are not exceeded as a result of reactor coolant loss due to leakage from the RCPB and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Design Evaluation

The total leakage rate limit is established so that, in the absence of normal ac power concomitant with a loss of feedwater supply, makeup capabilities are provided by the CRD and RCIC systems. While the LDS provides protection from small leaks, the ECCS provides protection for the complete range of discharges from ruptured pipes. Thus, protection is provided for the full spectrum of possible discharges to the extent that fuel-cladding temperature limits are not exceeded.

The plant is designed to provide ample reactor coolant makeup for protection against small leaks in the RCPB for AOOs and postulated accident conditions. The design of these systems meets the requirements of criterion 33.

For further discussion, see the following FSAR sections:

- *Nuclear System Leakage Detection and Leakage Rate Limits* 4.10
- *Reactor Core Isolation Cooling System* 4.7
- *Emergency Core Cooling System* 6.0
- *Reactor Vessel Instrumentation* 7.8

Criterion 34 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel-design limits and the design conditions of the RCPB are not exceeded.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The RHR system provides the means to:

- *Remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed.*
- *Condense reactor steam so that decay heat and residual heat may be removed if the normal heat sink is unavailable.*
- *Supplement the fuel pool cooling and cleanup system (FPCC) capacity during shutdown to provide additional cooling capacity.*

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and four service water pumps. The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation. The main system pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flowrate. The heat exchangers are sized on the basis of the required duty for the shutdown cooling function, which is the mode requiring the maximum heat exchanger capacity.

One loop consisting of a heat exchanger, two main system pumps in parallel, and associated piping is located in one area of the reactor building. The other heat exchanger, pumps, and piping that form a second loop are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system.

The RHR system is designed for the following four modes of operation:

- *Shutdown cooling.*
- *Containment cooling.*
- *Steam condensing.*
- *LPCI.*

Both normal ac power and an auxiliary onsite power system provide adequate power to operate all the auxiliary loads necessary for plant operation. The power sources for the plant auxiliary power system are sufficient in number, and of such electrical and physical independence, that no single probable event could interrupt all auxiliary power at one time.

The plant auxiliary buses supplying power to engineered safety features and RPS in addition to those auxiliaries required for safe shutdown are connected by appropriate switching to the standby diesel-driven generators located in the plant. Each power source, up to the point of its connection to the auxiliary power buses, is capable of complete and rapid isolation from any other source.

Loads important to plant operation and safety are split and diversified between switchgear sections, and means are provided for detection and isolation of system faults.

The plant layout is designed to effect physical separation of essential bus sections, standby generators, switchgear, interconnections, feeders, power centers, motor control centers, and other system components.

Three standby diesel generators are provided to supply a source of electrical power which is self contained within the plant and is not dependent on external sources of supply. The standby generators produce ac power at a voltage and frequency compatible with the normal bus requirements for essential equipment within the plant. Each of the diesel generators has sufficient capacity to start and carry the essential loads it is expected to drive. All of the auxiliary loads required for safe and orderly shutdown, including components of the RHR system, are duplicated and connected to separate buses.

The RHR systems are adequate to remove residual heat from the reactor core to ensure that fuel and RCPB design limits are not exceeded. Redundant offsite and onsite electric power systems are provided. The design of the RHR system, including their power supply, meets the requirements of criterion 34.

For further discussion, see the following FSAR sections:

• *Residual Heat Removal System*	*4.8*
• *Emergency Core Cooling System*	*6.0*
• *Emergency Core Cooling System Control and Instrumentation*	*7.4*
• *Auxiliary Electrical Power System*	*8.3*
• *Standby ac Power Supply*	*8.4*
• *Residual Heat Removal Service Water System*	*10.6*
• *Safety Analysis*	*HNP-2, 15.0*

Criterion 35 - Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that fuel and clad damage that could interfere with continued effective core cooling is prevented and clad metal water reaction is limited to negligible amounts.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The ECCS consists of the following:

- *HPCI system.*
- *Automatic depressurization system (ADS).*
- *Core spray (CS) system.*
- *LPCI (an operating mode of the RHR system).*

The ECCS is designed to limit fuel-cladding temperature over the complete spectrum of possible break sizes in the nuclear system process barrier including a complete and sudden circumferential rupture of the largest pipe connected to the reactor vessel.

The HPCI system consists of a steam turbine, a constant-flow pump, system piping, valves, controls, and instrumentation. The HPCI system is provided to assure that the reactor core is adequately cooled preventing excessive fuel-cladding temperatures for breaks in the nuclear system not resulting in rapid depressurization of the reactor vessel. HPCI continues to operate until reactor vessel pressure is below the pressure at which LPCI operation or CS system operation maintains core cooling. Two sources of water are available, namely the condensate storage tank and the suppression pool.

In case the capability of the feedwater pumps, CRD water pumps, RCIC, and HPCI is not sufficient to maintain the reactor water level, the ADS functions to reduce the reactor pressure so that flow from LPCI and the CS system enters the reactor vessel in time to cool the core and prevent excessive fuel-clad temperature. The ADS uses several of the nuclear system pressure relief valves to relieve the high-pressure steam to the suppression pool.

Two independent loops are provided as a part of the CS system. Each loop consists of a centrifugal water pump driven by an electric motor; a spray sparger in the reactor vessel above the core; piping and valves to convey water from the suppression pool to the sparger; and the associated controls and instrumentation. In case of low water level in the reactor vessel or high pressure in the drywell, the CS system automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flowrate to cool the core and prevent excessive fuel temperature. LPCI starts from the same signals which initiate the CS system and operates independently to achieve the same objective by flooding the reactor vessel.

In case of low water level in the reactor or high pressure in the containment drywell, the LPCI mode of operation of the RHR system pumps water into the reactor vessel in time to flood the core and prevent excessive fuel temperature. LPCI operation provides protection to the core in case of a large break in the nuclear system when the feedwater pumps and HPCI are unable to maintain reactor vessel water level. Protection provided by LPCI also extends to a small break where the ADS has operated to lower the reactor vessel pressure so that LPCI and the CS system start to provide core cooling.

Chapter 6 discusses the performance of the ECCS for the entire spectrum of liquid line breaks and provides the analysis that demonstrates the ECCS conforms to NRC criteria.

The redundancy and capability of the offsite and onsite electrical power systems for the ECCS are represented in the evaluation given in criterion 34.

The ECCS is adequate to prevent fuel and cladding damage which could interfere with effective core cooling and do limit cladding metal-water reaction to a negligible amount. Redundant offsite and onsite electric power systems are provided. The design of the ECCS, including power supply, meets the requirements of criterion 35.

For further discussion, see the following FSAR sections:

- *Residual Heat Removal System* — *4.8*
- *Emergency Core Cooling System* — *6.0*
- *Emergency Core Cooling System Control and Instrumentation* — *7.4*
- *Auxiliary Electrical Power System* — *8.3*
- *Standby ac Power Supply* — *8.4*
- *Residual Heat Removal Service Water System* — *10.6*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 36 - Inspection of Emergency Core Cooling Systems

The ECCS shall be designed to permit appropriate periodic inspection of important components, e.g., spray rings in the RPV, water injection nozzles, and piping, to assure the integrity and capability of the system.

Design Evaluation

The inservice inspection program for those portions of the ECCS defined by Section XI of the ASME Boiler and Pressure Vessel Code is described in appendix H. The CS spargers within the vessel are accessible for remote visual inspection during refueling outages. Removable plugs in the sacrificial shield and/or panels in the insulation provide access for examination of nozzles from the vessel outside diameter. Removable insulation is provided on the ECCS piping out to and including the first isolation valve outside containment.

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the reactor vessel is open for refueling or other purposes, the spargers and other internals can be inspected. Portions of the ECCS which are part of the RCPB are designed to specifications for inservice inspection to detect defects which might affect the cooling performance. Particular attention is given to the reactor nozzles and CS and feedwater spargers. The design of the reactor vessel and internals for inservice inspection and the plant testing and inspection program ensure that the requirements of criterion 36 are met.

Criterion 37 - Testing of Emergency Core Cooling Systems

The ECCSs shall be designed to permit appropriate periodic pressure and functional testing to assure the following:

- *Structural and leaktight integrity of its components.*

- *Operability and performance of the active components of the system.*

- *Operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.*

Design Evaluation

The ECCS consists of HPCI, ADS, LPCI mode of the RHR system, and CS. Each of these systems is provided with sufficient test connections and isolation valves to permit appropriate periodic pressure testing to assure the structural and leaktight integrity of its components.

The HPCI and CS systems, and LPCI as discussed in section 6.6, are designed to permit periodic testing to assure the operability and performance of the active components of each system.

The ECCS is subjected to tests to verify the performance of the full operational sequence that brings each system into operation.

The operation of applicable portions of the protection system is discussed in subsection 7.4.5, and testing of the emergency power sources is discussed in subsection 8.4.5. The operation of the associated cooling water systems is discussed in criterion 46. Subsection 4.8.11 and the Technical Specifications contain a more detailed discussion of the tests to which these systems are subjected.

Criterion 38 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and to maintain them at acceptably low levels.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure.

Design Evaluation

In the event of a LOCA within the reactor containment, the pressure suppression system will rapidly condense the steam to prevent containment overpressure. The containment feature of pressure suppression employs two separate compartmented sections of the primary containment, the drywell that houses the nuclear system and the suppression chamber containing a large volume of water. Any increase in pressure in the drywell from a leak in the nuclear system is relieved below the surface of the suppression chamber water pool by connecting vent lines, thereby condensing steam being released to the drywell. The pressure buildup in the suppression chamber is equalized with the drywell by a vent line and vacuum breaker arrangement. Cooling systems remove heat from the reactor core, the drywell, and *from the water in the suppression chamber during accident conditions, and thus provide continuous cooling of the primary containment.*

The ECCS is actuated to provide core cooling in the event of a LOCA. Low water level in the reactor vessel or high pressure in the drywell will initiate the ECCS to prevent excessive fuel temperature. Sufficient water is provided in the suppression pool to accommodate the initial energy which can transiently be released into the drywell from the postulated pipe failure.

The suppression chamber is sized to contain this water plus the water displaced from the reactor primary system together with the free air initially contained in the drywell.

Either or both RHR heat exchangers can be manually activated to remove energy from the containment. The redundancy and capability of the offsite and onsite electrical power systems for the RHR system are presented in the evaluation given in criterion 34.

The pressure suppression system is capable of rapid containment pressure and temperature reduction following a LOCA to ensure that the design limits are not exceeded. Redundant offsite and onsite electrical power systems are provided. The design of the containment heat removal system meets the requirements of criterion 38.

For further discussion, see the following FSAR sections:

- *Residual Heat Removal System* — *4.8*
- *Containment Systems* — *5.0*
- *Emergency Core Cooling System* — *6.0*
- *Emergency Core Cooling System Control and Instrumentation* — *7.4*
- *Auxiliary Electrical Power System* — *8.3*
- *Standby ac Power Supply* — *8.4*
- *Residual Heat Removal Service Water System* — *10.6*
- *Safety Analysis* — *HNP-2, 15.0*

Criterion 39 - Inspection of Containment Heat Removal System

The containment heat removal system (CHRS) shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles, and piping, to ensure the integrity and capability of the system.

Design Evaluation

Provisions are made to facilitate periodic inspections of active components and other important equipment of the containment pressure reducing systems. During plant operations, the pumps, valves, piping, instrumentation, wiring and other components outside the primary containment can be visually inspected periodically. Components inside the primary containment can be inspected when the drywell is open for access. The testing frequencies of most components are correlated with the component inspection.

The pressure suppression chamber is designed to permit appropriate periodic inspection. Space is provided outside the chamber for inspection and maintenance. There are two hatches that permit access to the suppression chamber for inspection.

The CHRS is designed to permit periodic inspection of major components both outside and within the primary containment. This design meets the requirements of criterion 39.

For further discussion, see the following FSAR sections:

- *Residual Heat Removal System* 4.8
- *Containment Systems* 5.0
- *Emergency Core Cooling System* 6.0
- *Emergency Core Cooling System Control and Instrumentation* 7.4
- *Residual Heat Removal Service Water System* 10.6

Criterion 40 - Testing of Containment Heat Removal System

The CHRS shall be designed to permit appropriate periodic pressure and functional testing to ensure the following:

- *Structural and leaktight integrity of its components.*
- *Operability and performance of the active components.*
- *Operability of the system as a whole and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.*

Design Evaluation

The CHRS function is accomplished by the suppression pool cooling mode of the RHR system. This mode is discussed in HNP-2-FSAR section 15.3 and consists of the suppression pool cooling mode of RHR and the core spray system.

Criterion 41 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), its safety function can be accomplished, assuming a single failure.

Design Evaluation

Fission products released into the reactor building following postulated accidents are automatically processed by the SGTS. The SGTS initiation follows high-radiation signals from monitors in the refueling floor exhaust duct from monitors in the reactor building exhaust duct, or from primary containment isolation system signal. The ability of this system to remove radioactivity from the process stream is discussed in paragraph 5.3.3.3.

The SGTS is composed of two trains which are separated physically and electrically so that a single failure will not prevent its function. The redundancy of this system is discussed in paragraph 5.3.3.3.

The SGTS units are connected by a flow orifice downstream of the first carbon bed in each train and upstream of the second carbon bed in each train. This maintains a small continuous flow through the inactive train to assure cooling for the first carbon bed when loaded with radionuclides. Each train of the SGTS is powered from redundant portions of the emergency ac power system. The trains discharge to a common pipe leading to the main stack. A discharge radiation monitor and flow monitor are located in the common discharge. The suction to the trains is common also; the suction valves which may have to operate after an accident are air operated and are designed to fail so that containment isolation and reactor building evacuation via the SGTS are assured.

Paragraph 5.3.3.3 discusses SGTS operation. Table 7.3-1 indicates containment isolation, and section 8.4 discusses the availability of power.

<u>Criterion 42 - Inspection of Containment Atmosphere Cleanup System</u>

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping, to assure the integrity and capability of the systems.

Design Evaluation

Inspection of the internal structure of the SGTS filter banks is facilitated by access doors installed in each unit to allow entry to the unit for visual inspection of structural members and filter faces.

A glove port is provided downstream of each high-efficiency particulate air (HEPA) filter to facilitate scanning of each filter bank with a radiation probe.

Each charcoal bed is provided with facilities for taking a charcoal sample.

For further discussion of SGTS features, refer to paragraph 5.3.3.3.

<u>Criterion 43 - Testing of Containment Atmosphere Cleanup Systems</u>

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure:

- *Structural and leaktight integrity components.*
- *Operability and performance of the systems' active components such as fans, filters, dampers, pumps, and valves.*
- *Operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.*

Design Evaluation

Each unit of the SGTS is periodically operated to ascertain the operability and performance of the major active components, such as fans, filter, motors, and valves, and also the structural integrity of the unit. This test also verifies the operability of the system as a whole and the operability of all associated subsystems. See subsection 8.4.5 for a discussion of auxiliary power system testing.

The leaktightness of the filters is measured by the dioctyl phthalate test. The charcoal beds are checked for bypass with freon 112.

<u>Criterion 44 - Cooling Water</u>

A system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The RHRSW and the PSW systems transfer the heat loads from structures, systems, and components important to safety during normal operating, shutdown, and accident conditions (sections 10.6 and 10.7).

The RHRSW and PSW systems are designed with sufficient redundance of components and piping so that no single failure can prevent achieving the safety cooling objective (subsections 10.6.6 and 10.7.6).

Assuming a single failure, the electrical power supplies to valving are such that at least one train of cooling water is provided. Sufficient redundancy exists in the electrical power supply to ensure that minimum safety pumping requirements are met (section 8.4).

<u>Criterion 45 - Inspection of Cooling Water System</u>

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Design Evaluation

To the extent practical and consistent with other design considerations, the components of the RHRSW and PSW systems have are to facilitate visual inspection (subsections 10.6.7 and 10.7.7).

<u>Criterion 46 - Testing of Cooling Water System</u>

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to ensure:

- *Structural and leaktight integrity of components.*
- *Operability and performance of the systems' active components.*
- *Operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCAs, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.*

Design Evaluation

The pumps and automatic valves are periodically tested to verify operation. Since the PSW system is normally in operation, no special tests are required to ensure that the system can operate in an emergency. Periodic tests are conducted to verify the automatic initiation of the RHRSW system. The RHRSW system has no automatic initiation features but operation is verified. The specific tests which are conducted are discussed more fully in the Technical Specifications. Chapter 8 discusses the tests that ensure the availability of electrical power. The pumps and valves of these systems necessary for emergency operation are powered from a standby ac distribution system.

Criterion 50 - Containment Design Basis

The reactor containment structure, including access openings, penetrations, and the CHRS, shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA. This margin shall reflect consideration of the following:

- *Effects of potential energy sources not included in the determination of the peak conditions, such as energy in steam generators and energy from metal water and other chemical reactions that may result from degraded emergency core cooling functioning.*

- *Limited experience and experimental data available for defining accident phenomena and containment responses.*

- *Conservatism of the calculational model and input parameters.*

Design Evaluation

The containment structure, access openings, penetrations, heat removal system, and internal compartments are designed to accommodate the pressure and temperature conditions resulting from the LOCA described in HNP-2-FSAR paragraph 6.2.1.4.2, without exceeding the leakage rate incorporated in the Technical Specifications.

The 11.5-psi margin between the calculated peak drywell pressure of 50.5 and the maximum internal pressure of 62 psig allowed by the ASME Boiler and Pressure Vessel Code, Section III, is considered sufficient for the following reasons:

A. *The containment vessel has the capability of arbitrarily tolerating large metal-water reactions.*

B. *A large body of experimental data has been obtained on BWR suppression containment performance.*

C. *Conservative assumptions have been used in the containment response analytical model described in HNP-2-FSAR paragraph 6.2.1.4.2.*

<u>Criterion 51 - Fracture Prevention of Containment Pressure Boundary</u>

The reactor containment boundary shall be designed with sufficient margin to assure that, under operating, maintenance, testing, and postulated accident conditions, ferritic materials behave in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions and the uncertainties in determining material properties; residual, steady-state, and transient stresses; and size of flows.

Design Evaluation

The reactor containment vessel is fabricated to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, subsection B for nuclear vessels. This code in Article 12 gives recognition to the requirement that containment materials behave in a ductile manner for all conditions of service, thus assuring that ferritic materials behave in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. The lowest design service temperature is conservatively taken as 30°F. The actual service temperature is calculated to be ~ 135°F. Thus, sufficient margin is inherent in the design to account for the various uncertainties involved in design and fabrication.

<u>Criterion 52 - Capability for Containment Leakage Rate Testing</u>

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Design Evaluation

The primary reactor containment and other equipment including the personnel air lock and isolation valves are designed to permit periodic integrated leakage rate testing at containment design pressure. A more complete discussion can be found in paragraph 5.2.5.1 and in the Technical Specifications.

<u>Criterion 53 - Provisions for Containment Testing and Inspection</u>

The reactor containment shall be designed to permit the following:

- *Appropriate periodic inspection of all important areas such as penetrations.*

- *Appropriate surveillance program.*

- *Periodic testing at containment design pressure of the leaktightness of penetrations having resilient seals and expansion bellows.*

Design Evaluation

The reactor containment is designed to optimize the accessibility of important areas to permit required inspection and surveillance.

All penetrations with resilient seals or expansion bellows are the double-seal type. The space between the seals may be periodically pressurized to containment design pressure and their leaktightness verified (paragraph 5.2.5.2).

For further discussion, see the following FSAR sections:

- *Reactor Vessel Internals Mechanical Design* — *HNP-2, 4.2*
- *Reactor Vessel and Appurtenances Mechanical Design* — *4.2*
- *Emergency Core Cooling System* — *6.0*

Criterion 54 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to periodically test the operability of isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Design Evaluation

Piping systems penetrating the drywell are accorded special design considerations to reflect their importance in accomplishing safety-related functions and in achieving isolation, if required. The penetrations are discussed in paragraphs 5.2.3.4 and 5.2.4.7. Both the isolation valving and the system initiating isolation use components whose quality maximizes reliability and are provided with sufficient independence and redundancy to optimize the isolation function, if required. Containment isolation is discussed in paragraphs 5.2.5.3 and 5.2.4.8, and the system initiating isolation is discussed in section 7.3.

The operation of remote-manual isolation valves is periodically verified according to the Technical Specifications. Sufficient test connections are provided to each of these piping systems to ensure that minimal valve leakage is achieved and maintained (subsection 5.2.5).

Criterion 55 - RCPB Penetrating Containment

Each line that is part of the RCPB and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

- *One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.*

- *One automatic isolation valve inside and one locked-closed isolation valve outside containment.*

- *One locked-closed isolation valve inside and one automatic isolation valve outside containment -- A simple check valve may not be used as the automatic isolation valve outside containment.*

- *One automatic isolation valve inside and one automatic isolation valve outside containment -- A simple check valve may not be used as the automatic isolation valve outside containment.*

Isolation valves outside containment shall be located as close to the containment as practical; and upon loss-of-actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided, as necessary, to assure adequate safety. Determination of the appropriateness of these requirements, e.g., higher quality in design, fabrication, and testing; additional provision for inservice inspection; protection against more severe natural phenomena; and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Design Evaluation

The RCPB consists of the RPV, the pressure-retaining appurtenance attached to the vessel, and valves and pipes which extend from the RPV up to and including the outermost isolation valve. The lines of the RCPB penetrating the primary containment are capable of isolating the containment, thereby precluding any significant release of radioactivity. Similarly, for lines not penetrating the primary containment but forming a portion of the RCPB, the design ensures that isolation from the RCPB can be achieved.

A. *Influent Lines*

Influent lines penetrating the primary containment and connecting directly to the RPV are equipped with two isolation valves--one inside the containment and the other located outside and as close to the containment as possible.

Table F.3-1 lists those influent pipes comprising the RCPB. The purpose of the table is to review the design of each line with respect to the requirements imposed by criterion 55. The paragraphs referenced in table F.3-1 demonstrate that although a word-for-word comparison with criterion 55 in some cases is not practical, it is possible to demonstrate adequate isolation provisions on some other defined basis.

Comment 55.1

The portion of the feedwater line forming part of the RCPB and penetrating the primary containment has two isolation valves. Both valves are simple check valves; one is located inside the primary containment and the other located outside the primary containment. Should a break occur in the feedwater line, the check valves prevent significant loss of inventory and offer immediate isolation. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all supply sources. For this reason, the outer feedwater isolation valve does not automatically isolate upon signal from the protection system.

It should be noted that criterion 55, which became effective subsequent to completion of the feedwater system design, states that a simple check valve may not be used as the isolation valve outside the containment. Although the feedwater line does not conform to this requirement, it does conform to the requirements in effect at the time the system was designed (10 CFR 50, Appendix A, General Design Criteria for Nuclear Power Plant Construction Permits).

Comment 55.2

Influent lines connecting to process piping but not penetrating the primary containment must adequately reflect the importance to safety of isolating these piping systems. Pipes of this type include those portions of RCIC, RWC, and HPCI lines that tie into the feedwater line. The RCIC and HPCI lines have motor-operated, automatic, and remote manually actuated gate valves that are closed during normal operation; whereas, the RWC line is open during operation and has a simple check valve to provide positive assurance of isolation in the event of a break upstream of this valve. In addition to the check valve, the RWC line has a normally open, remote manually actuated motor-operated globe valve capable of providing leakage control. The CRD return line, connected upstream of the RWC check valve, has an additional check valve capable of providing leakage control.

Comment 55.3

The RHR return lines to the recirculation system and the CS lines have check valves inside the containment which provide for immediate isolation in the event of a break upstream of these valves. In addition, the isolation valves outside the containment are normally closed, automatic and remote manually actuated valves designed to provide long-term leakage control in the event of a break in these lines. For the postulated LOCA, the protection system initiates automatic opening of the CS injection valves at the appropriate time to assure that acceptable fuel-design limits are not exceeded.

Comment 55.4 (Deleted)

Comment 55.5 (Deleted)

Comment 55.6

The SLC line utilizes a simple check valve as the isolation valve inside as well as outside the primary containment. Criterion 55 states that a simple check valve may not be used as the automatic isolation valve outside the containment; however, should insertion of the liquid poison become necessary, it is imperative that the injection line be open. In the design of this system, it has been the accepted practice to omit an automatic valve from opening upon signal because of the introduction of possible failure mechanism. As a means of providing assurance for reliable, timely actuation, an explosive valve is used.

In this manner, the availability of the line is assured. Because the SLC line is a closed, nonflowing line, rupture of this line is very remote; however, should a break occur, the check valves provide positive actuation for immediate isolation.

Comment 55.7

CRD Insert and Withdraw Lines

Criterion 55 applies to lines of the RCPB penetrating the primary reactor containment. The CRD insert and withdraw lines are not part of the RCPB.

The basis to which the CRD lines are designed is commensurate with the safety importance of isolating these lines. Since these lines are vital to the scram function, their operability is of utmost concern.

In the design of this system, it has been accepted practice to omit automatic valves for isolation purposes because of the introduction of a possible failure mechanism. As a means of providing positive actuation, manual shutoff valves are used. In the event of a break on these lines, the manual valves may be closed to ensure isolation. In addition, a ball valve located within the insert line is designed to automatically seal this line in the event of a break.

Finally, several breaks and combinations of breaks in the CRD lines were postulated and analyzed (HNP-2-FSAR section 4.2). The results of these analyses indicate that the worst situation causes a leak rate which is negligible compared to the makeup capability.

TIP System

Since the TIP system lines do not communicate freely with the containment atmosphere and since they do not comprise a portion of the RCPB, criteria 56 and 55 are not directly applicable to this specific class of lines. The basis to which these lines are designed is more closely described by criterion 54, which states in effect that isolation capability of a system be commensurate with the safety importance of the isolation. Furthermore, even though the failure of the TIP system lines presents no safety hazard, the system has redundant isolation capabilities. These and other safety features are described in the following paragraphs.

When the TIP system cable is inserted, the ball valve of the selected tube opens automatically so that the probe and cable may advance. A maximum of four valves may be opened at any one time to conduct the calibration; and any one guide tube is used, at most, a few hours per year.

If closure of the line is required during calibration, a signal causes the cable to retract and the ball valve to close automatically after completion of cable withdrawal. To ensure isolation capability if a TIP cable fails to withdraw or a ball valve fails to close, an explosive shear valve is installed in each line. Upon receipt of a signal, this explosive valve shears the TIP cable and seals the guide tube.

Effluent Lines

Effluent lines forming part of the RCPB and penetrating the primary containment are equipped with two isolation valves; one is located inside the containment and the other is located outside and as close to the containment as possible.

Table F.3-2 lists those effluent pipes comprising the RCPB and penetrating the primary containment.

Aside from the MSIVs, each valve is a motor-operated, automatic or remote manually actuated gate valve capable of providing adequate isolation protection in the event of a break in these lines. The MSIVs are air-operated, automatic and remote manually actuated globe valves which provide two distinct barriers against containment leakage. Upon loss-of-actuating power, automatic isolation valves assume the position providing greater safety. The protection system initiates automatic isolation under accident conditions for effluent lines that are normally open during operation and not part of the overall safety system network.

Summary

To assure protection against the consequences of accidents involving the release of radioactive material, pipes forming the RCPB have been shown to provide adequate isolation capabilities on a case-by-case basis. In all cases, a minimum of two barriers was shown to protect against the release of radioactive materials. Adequate isolation capabilities were also demonstrated for pipes connecting to the feedwater line outside the primary containment.

In addition to meeting the isolation requirements stated in criterion 55, the pressure-retaining components comprising the RCPB are designed to meet other appropriate requirements which minimize the probability or consequences of an accidental rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards of all reactor plant components.

It can, therefore, be concluded that the design of piping systems comprising the RCPB satisfies criterion 55.

For further discussion, see the following FSAR sections:

- *Primary Containment Isolation Valves* 5.2
- *Primary Containment and Reactor Vessel Isolation Control System* 7.3

<u>*Criterion 56 - Primary Containment Isolation*</u>

Each line connecting directly to the containment atmosphere and penetrating the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

- *One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.*

- *One automatic isolation valve inside and one locked-closed isolation valve outside containment.*

- *One locked-closed isolation valve inside and one automatic isolation valve outside containment -- A simple check valve may not be used as the automatic isolation valve outside containment.*

- *One automatic isolation valve inside and one automatic isolation valve outside containment -- A simple check valve may not be used as the automatic isolation valve outside containment.*

Isolation valves outside containment shall be located as close to the containment as practical and, upon loss-of-actuating power, automatic isolation valves shall be designed to take the position providing greater safety.

Design Evaluation

Lines penetrating the primary containment and communicating with the containment interior may be grouped into three categories:

- *Pipes communicating with the drywell or suppression chamber atmosphere.*

- *Influent lines to the suppression pool.*

- *Effluent lines from the suppression pool.*

A. *Lines Communicating with the Drywell or Suppression Chamber Atmosphere*

   Lines penetrating the primary containment and communicating with the drywell or suppression chamber atmosphere are generally provided with two automatic isolation valves in series located outside the drywell. This deviation from the design criteria is considered safe and adequate for the following reasons:

   1. *There is limited space within the drywell; therefore, placement of these valves inside would seriously impede accessibility for inspection and maintenance of these valves and other equipment.*

   2. *Placement of these valves inside the containment would subject them to an inimical environment, thus increasing the probability of failure.*

   3. *Some of the lines falling into this category are not in use during normal operation and are, therefore, isolated.*

4. *Valves should be accessible in systems which must be available for long-term operation following an accident. Examples are the containment atmosphere monitoring lines and the nitrogen inerting makeup lines.*

   All automatic valves are capable of remote-manual operation and are closed upon receipt of an isolation signal as shown in table 7.3-1.

   There are two lines not having automatic isolation valves -- the service air line and the demineralized water line. Each of these penetrations is isolated by locked-closed manual valves; one is located inside the primary containment and the other is located outside the primary containment.

B. *Influent Lines to Suppression Pool*

The reasons for not placing valves inside the suppression chamber are similar to those mentioned in the preceding section. The following discussion provides unique considerations as to the types of valves and isolation capabilities.

1. *RCIC and HPCI Turbine Exhaust Lines, HPCI Turbine Condensate Line, and RCIC Vacuum Pump Discharge Line.*

   These lines penetrating the primary containment and connecting to the suppression pool are equipped with a normally open, stop-check globe valve located as close to the containment as possible. This valve is manually actuated and provides long-term leakage control in the event of a line break. In addition, there is a simple check valve upstream of each globe valve which provides positive actuation for immediate isolation in the event of a break. It should be noted that these lines have a leaktight water seal that adds yet another level of protection; i.e., any gas which might be present in the airspace of the suppression chamber cannot leak through these lines.

2. *Minimum Flow and Test Lines*

   These lines have isolation capabilities commensurate with the importance to safety of isolating these lines. The RHR, HPCI, RCIC, and CS minimum flow lines have two valves in series, both of which are located outside the primary containment. The upstream valve is a check valve, and the downstream valve is a motor-operated gate valve. The motor-operated valve serves as a flow control valve to ensure proper minimum flow through the pump. Since the operation of the bypass lines is important to the operation of the safety systems and since automatic isolation valves could degrade the reliability of these systems, no further valving has been incorporated.

   To meet the isolation requirements, the RHR and CS test lines have a normally closed isolation valve in addition to the water seal.

C. Effluent Lines from Suppression Pool (RHR, CS, HPCI, and RCIC)

It should be noted that criterion 56 does not reflect consideration of the BWR suppression pool design. These lines do not have an isolation valve located inside the containment because this would necessitate placement of the valve under water. In effect, this would result in introducing a potentially unreliable valve to a highly reliable system, thereby compromising design. For this reason, these lines incorporate two valves outside the containment. The first valve is an air-operated butterfly valve located as close to the containment as possible. The second valve is a motor-operated, remote manually actuated gate valve. Due to the importance of these suction lines to core cooling, none of these valves receive an automatic isolation signal.

Summary

To assure protection in the event of accidents involving release of significant amounts of radioactive material into the primary containment, pipes penetrating the primary containment have been provided with isolation capabilities in accordance with the intent of criterion 56. In all cases, these pipes have been provided with a minimum of two, in some cases more, protective barriers against containment leakage.

<u>Criterion 57 - Closed- System Isolation Valves</u>

Each line penetrating the primary reactor containment that is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked-closed, or capable of remote-manual operation. This valve shall be located outside and as close to the containment as practical.

A simple check valve may not be used as the automatic isolation valve.

Design Evaluation

The HNP-1 design was reviewed, compared to the requirements, and determined to be in compliance with this design criterion. This subject is further discussed in paragraph 5.2.3.5 and section 7.3.

<u>Criterion 60 - Control of Releases of Radioactive Materials to the Environment</u>

The nuclear power unit design shall include means to suitably control the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive material, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Design Evaluation

The radioactive waste systems are designed to collect, process, and dispose of potentially radioactive wastes produced during the operation of the plant. These systems are discussed in chapter 9.

The liquid radwaste system is designed to process and recycle the liquid waste collected in the waste holdup tank, to the extent practicable. Liquid waste collected in chemical or floor drain tanks are normally discharged to the environment after treatment and dilution with cooling tower blowdown. An evaporator and a floor drain filter have been added to the liquid radwaste system to provide further capability for minimizing liquid radioactive releases. During normal plant operation, the annual average whole-body radiation dose to individuals from both onsite reactors, resulting from these routine liquid waste discharges, is expected to be about 3% of 10 CFR 20 limits. Short-term releases from the plant, resulting from equipment malfunctions or AOOs, are within the 10 CFR 20 limits.

Solid wastes are packaged in suitable containers for onsite storage, offsite shipment, and burial.

Prior to discharge to the environs, the air ejector off-gas radioactive wastes are treated by an ambient charcoal bed adsorption system. An off-gas recombiner has been added downstream of the steam jet air ejectors to recombine hydrogen and oxygen, thereby increasing holdup time. The charcoal adsorption system has also been added. This system increases the effective holdup time for the isotopes of krypton and xenon and significantly reduces their release to the environment. The annual average exposure at the site boundary due to noble gases from both units during normal operation is not expected to exceed 30 mrem.

The liquid and gaseous effluents from the treatment systems are continuously monitored, and the discharges are terminated if the effluents exceed preset radioactivity levels.

The radioactive waste treatment system design discussed in this section limits the radioactivity releases to the environs from HNP to levels as low as practical.

Criterion 61 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed as follows:

- *With a capability to permit appropriate periodic inspection and testing of components important to safety.*

- *With suitable shielding for radiation protection.*

- *With appropriate containment, confinement, and filtering systems.*

- *With a RHR capability having reliability and testability that reflects the importance to safety of decay heat and other RHR.*

- *With the capability to prevent significant reduction in fuel storage coolant inventory under accident conditions.*

Design Evaluation

A. New-Fuel Storage

New fuel is placed in dry storage in the new-fuel storage vault located inside the secondary containment reactor building. The storage vault within the reactor building provides adequate shielding for radiation protection. Storage racks preclude accidental criticality. (See General Design Criterion (GDC) 61.) The new-fuel storage racks do not require any special inspection and testing for nuclear safety purposes.

B. Spent-Fuel Handling and Storage

The handling of new- and spent-fuel assemblies for reactor refueling is within the reactor building. Fuel storage pool water is allowed to flood the reactor well to provide shielding above the reactor and spent fuel. Fuel pool water is circulated through the FPCC system to maintain fuel pool water temperature, purity, water clarity, and water level. Storage racks preclude accidental criticality. (See GDC 62.)

Reliable decay heat removal is provided by the closed-loop FPCC system. It consists of two circulating pumps, two heat exchangers, two filter-demineralizers, two skimmer surge tanks, and the required piping, valves, and instrumentation. The pool water is circulated through the system, suction is taken from surge tanks, and flow passes through the heat exchanger and filters and is discharged through diffusers at the bottom of the fuel pool and reactor well. Pool water temperature is maintained below 150°F when removing the maximum normal heat load from the pool with the RBCCW temperature at its maximum. If it appears that the pool temperature will exceed 150°F, the FPCC system can be connected to the RHR system, thereby increasing the cooling capacity of the FPCC system. Also, the decay heat removal system can be utilized to remove decay heat from the fuel pool.

There are no connections to the fuel storage pool allowing the fuel pool to be drained below the pool gate between the reactor well and fuel pool. The high- and low-level switches indicate pool water level changes in the control room and pump room. Fission product concentration in the pool water is minimized by use of the filter-demineralizer, thereby minimizing the release from the pool to the reactor building environment. No special tests are required because at least one pump, heat exchanger, and filter-demineralizer are continuously in operation while fuel is stored in the pool. Duplicate units are periodically operated to handle abnormal heat loads or to replace a unit for servicing. Routine visual inspection of the system components, instrumentation, and trouble alarms are adequate to verify system operability.

C. Radioactive Waste Systems

The radioactive waste systems provide all equipment necessary to collect, process, and prepare for disposal of all radioactive liquids, gases, and solid waste produced as a result of reactor operation.

Liquid radwastes are classified, contained, and treated as high- or low-conductivity, chemical, detergent, sludges, or concentrated wastes. Processing includes filtration, ion exchange, analysis, and dilution. Liquid wastes are also decanted, and sludge is accumulated for disposal as solid radwaste. Dry solid radwastes are packaged in shielded steel or fiber drums, cartons, or boxes. Gaseous radwastes are monitored, processed, recorded, and controlled so that radiation doses to persons outside the controlled area are below those allowed by 10 CFR 20.

Accessible portions of the reactor and radwaste buildings have sufficient shielding to maintain dose rates within the limits set forth in 10 CFR 20. The radwaste building is designed to preclude accidental release of radioactive materials to the environs.

The radwaste systems are used on a routine basis and do not require specific testing to assure operability. Performance is monitored by radiation monitors during operation.

The fuel storage and handling and radioactive waste systems are designed to assure adequate safety under normal and postulated accident conditions.

The design of these systems meets the requirement of GDC 61.

For further discussion, see the following FSAR sections:

- *Residual Heat Removal System* *4.8*
- *Containment Systems* *5.0*
- *Radioactive Waste Systems* *9.0*
- *New-Fuel Storage* *10.2*
- *Spent-Fuel Storage* *10.3*
- *Fuel Pool Cooling and Cleanup System* *10.4*
- *Heating, Ventilating and Air-Conditioning Systems* *10.9*
- *Structures and Shielding* *12.0*

Criterion 62 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Design Evaluation

Appropriate plant fuel-handling and storage facilities are provided to preclude accidental criticality for new and spent fuel. Criticality in new- and spent-fuel storage is prevented by the geometrically safe configuration of the storage rack. There is sufficient spacing between the assemblies to assure that the array when fully loaded is substantially subcritical. Fuel elements are limited by rack design to only top loading and fuel assembly positions. The new- and spent-fuel racks are Class I structures.

New fuel is placed in dry storage in the top-loaded new-fuel storage vault. The vault contains a drain to prevent the accumulation of water. The new-fuel storage vault racks located inside the secondary containment reactor building are designed to prevent an accidental critical array, even in the event the vault becomes flooded or subjected to seismic loadings. The new-fuel storage vault is such that the K_{eff} dry is not > 0.90, and the K_{eff} flooded is not > 0.95.

Spent fuel is stored under water in the spent-fuel pool. The racks in which spent-fuel assemblies are placed are designed and arranged to ensure subcriticality in the storage pool. All arrangements of fuel in the spent-fuel storage racks are maintained in a subcritical configuration having a K_{eff} not > 0.95.

Refueling interlocks include circuitry which senses conditions of the refueling equipment and the control rods. These interlocks reinforce operational procedures that prohibit making the reactor critical. The fuel-handling system is designed to provide a safe, effective means of transporting and handling fuel and minimize the possibility of mishandling or maloperation.

The use of geometrically safe configurations for new- and spent-fuel storage and the design of fuel-handling systems precludes accidental criticality in accordance with GDC 62.

For further discussion, see the following FSAR sections:

- *Refueling Interlocks* 7.6
- *New-Fuel Storage* 10.2
- *Spent-Fuel Storage* 10.3

Criterion 63 - Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and in associated handling areas to detect conditions that may result in loss of RHR capability and excessive radiation levels and to initiate appropriate safety actions.

Design Evaluation

Appropriate systems have been provided to meet the requirements of this criterion. A malfunction of the FPCC resulting in loss of RHR capability and excessive radiation levels is alarmed in the control room. Alarmed conditions include low fuel pool cooling water pump discharge pressure, high and low levels in the fuel storage pool and skimmer surge tanks, and flow in the drain lines between fuel pool gates (located between the fuel pool and the reactor well). System temperature is also continuously monitored and alarmed in the control room. Spent-fuel storage is discussed in section 10.3, and FPCC is discussed in section 10.4.

The reactor building ventilation radiation monitoring system detects abnormal amounts of radioactivity and initiates appropriate action to control the release of radioactive material to the environs. These systems are discussed in sections 5.3 and 7.12.

Area radiation and tank and sump levels are monitored and alarmed, indicating conditions that may result in excessive radiation levels in radioactive waste system areas. These systems are discussed in sections 9.2, 9.3, 9.4, and 7.13.

Criterion 64 - Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of LOCA fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Design Evaluation

A fission products monitoring system samples the containment atmosphere for radioactive particulates, noble gases, and iodine during normal operation. A hydrogen-oxygen analyzer system monitors the oxygen and hydrogen concentration in the containment during normal operation and following an accident.

Radioactive effluent discharge paths are monitored (chapter 9 and section 7.12), and the site environs are monitored for radioactivity releases (section 2.6).

TABLE F.3-1

CRITERION 55 - REACTOR COOLANT PRESSURE BOUNDARY

Influent Lines	*Inside Drywell*	*Outside Drywell*	*Comments*
Feedwater	*CV*[a]	*CV*	*55.1*
HPCI return	-	*MOV*[b]	*55.2*
RCIC return	-	*MOV*	*55.2*
Cleanup return	-	*CV*	*55.2*
RHR return to recirculation	*CV*	*MOV*	*55.3*
CS	*CV*	*MOV*	*55.3*
CRD return	*CV*	*CV*	*55.2*
SLC	*CV*	*CV*	*55.6*
Other	-	-	*55.7*

a. CV - Check valve .
b. MOV - Motor-operated valve.

TABLE F.3-2

REACTOR COOLANT PRESSURE BOUNDARY

Effluent Lines	Inside Drywell	Outside Drywell
Main steam	AOV[a]	AOV
RWC	MOV	MOV
RHR shutdown cooling	MOV	MOV
Main steam drain	MOV	MOV
RCIC turbine steam	MOV	MOV
HPCI turbine steam	MOV	MOV

a. AOV - Air-operated valve.

APPENDIX G

PLANT NUCLEAR SAFETY OPERATIONAL ANALYSIS

See HNP-2-FSAR supplement 15C, Plant Nuclear Safety Operational Analysis.

APPENDIX H

INSERVICE INSPECTION PROGRAM

H.1 GENERAL

Inservice inspection is described in the Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2 Inservice Inspection Program. Inservice testing is described in the Edwin I. Hatch Nuclear Plant Unit 1 and Unit 2 Inservice Testing Program. These documents describe the programs for Class 1, 2, and 3 component and piping examinations, and pump and valve surveillance testing. Each document is updated, as required, to meet the requirements of 10 CFR 50.55a and is submitted to the NRC for review and approval. It should be noted that the classification of components as American Society of Mechanical Engineers (ASME) Class 1, 2, or 3 equivalent for inservice inspection does not imply that the components were designed in accordance with ASME requirements. The component design codes remain as stated in the Final Safety Analysis Report.

H.2 RESPONSIBILITY

Southern Nuclear Operating Company (SNC) bears the overall responsibility for the performance of the inservice examinations. Certain nondestructive examinations are performed by a qualified examination agency. The results of such examinations are reported to SNC for final evaluation and disposition.

H.3 RECORDS

Records and documentation of all information and inspection results, which provide the basis for evaluation and which facilitate comparison with results from previous and subsequent inspections, are maintained and available for the active life of the plant in accordance with American Society of Mechanical Engineers, Section XI, IWA-6000.

H.4 METHODS OF EXAMINATION

Methods of examination and qualification of personnel are defined by ASME Code Section XI (as specified in 10 CFR 50.55a).

H.5 REPAIR PROCEDURES

Code repairs of ASME Section III Class 1, 2, or 3 (equivalent) pressure retaining components are performed in accordance with the requirements of ASME Code Section XI (as specified in 10 CFR 50.55a).

APPENDIX I

REACTOR PRESSURE VESSEL DESIGN INFORMATION

I.1 DESIGN AND FABRICATION REQUIREMENTS

The Edwin I. Hatch Nuclear Plant-Unit 1 (HNP-1) reactor vessel was designed, fabricated, inspected, and tested in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1965 Edition and addenda to and including winter 1966 addenda, and the following additions:

- Low-alloy steel plate for pressure parts in accordance with ASME SA-533, Grade B, Class 1 material and Code Cases 133B-3 and 1339-2.
- Low-alloy steel forgings to pressure parts in accordance with ASME SA-508, Class 2 material, Code Case 1332-4.
- Inconel nozzles in accordance with SB-166 material, Code classes 1336 and 1359-1.
- Nozzle ends for austenitic pipe and flange ends for low-allow steel nozzles in accordance with SA-105 Grade II material, Code Case 1332-4.
- Studs, nuts, bushings, and washers in accordance with American Society of Testing Materials A-540, Grade 24 material and Code Case 1335.
- Shroud support legs, baffle plate, and ring in accordance with SB-168 material, Code Case 1336.

The date of the contract between the buyer, General Electric (GE) Company, Atomic Power Equipment Department, San Jose California, and the seller, Combustion Engineering, Inc., Chattanooga, Tennessee, was February 1, 1967. There are no deviations to the Code throughout the design, fabrication, inspection, and testing of the reactor vessels.

Design, fabrication, inspection, and test requirements in addition to those required by the ASME Code were required as follows:

A. Established specific maximum nil ductility transition temperatures (NDTTs) for the main closure flanges and the shell and head materials connecting to these flanges (± 10°F NDTT) and elsewhere (40°F NDTT).

B. Vessel flange O-ring seating may be performed with the reactor vessel at room temperature. Design boltups for operation are made with the reactor vessel at 100°F.

C. Provisions are made for determining the effects of nuclear radiation upon the reactor vessel structural materials by supplying surveillance specimens of the vessel material to be exposed to the core irradiation at the vessel wall inside of the vessel. These include tensile and Charpy test specimens.

Pertinent certifications are contained in reference 1.

The summary of results of the detailed stress analysis is contained in reference 2.

A detailed seismic analysis of the reactor vessel support structure was prepared by GE and a summary of this report, along with a summary of the reactor vessel and internal components seismic analysis, is contained in reference 3.

The HNP-1 reactor vessel was fabricated so as to eliminate all furnace-sensitized wrought stainless steel base metal from all reactor vessel components.

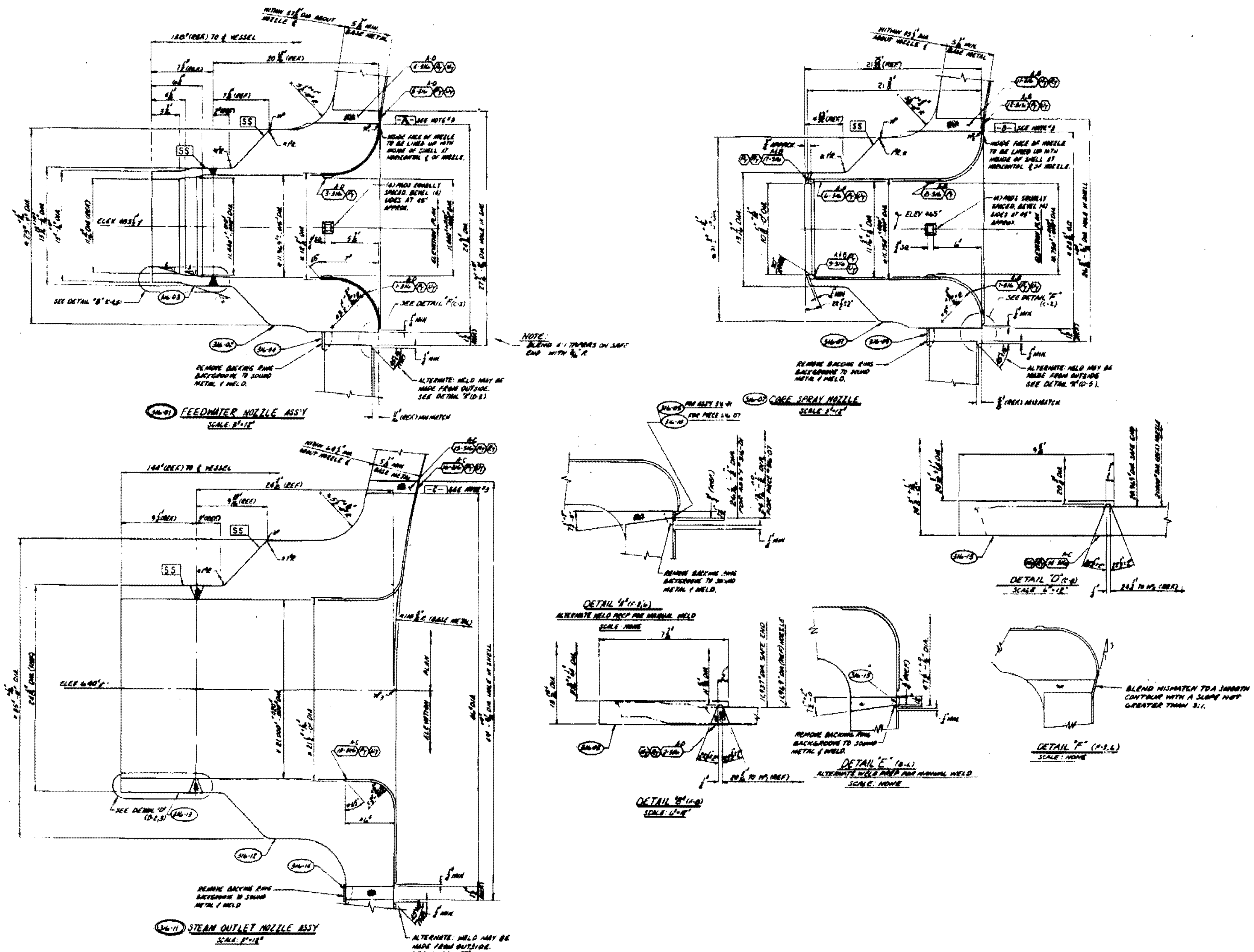
Details of the reactor vessel are shown in figures 1.1-1 and on drawing nos. S-15062, S-15213, S-15227, S-15523, and S-15524.

REFERENCES

1. "Certification of Pressure Vessel Design Specification," General Electric Company, June 24, 1971.

2. "Hatch Unit 1 Reactor Vessel Summary Stress Report," General Electric Company.

3. "Seismic Analysis of Edwin Hatch-1 Nuclear Plant," DAR-139, General Electric Company.



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EDWIN I. HATCH NUCLEAR PLANT
UNIT 1

FEEDWATER, STEAM, AND CORE SPRAY NOZZLE DETAILS

FIGURE I.1-1

APPENDIX J

IDENTIFICATION - RESOLUTION OF AEC-ACRS AND STAFF CONCERNS

J.1 SUMMARY DESCRIPTION

The design of the General Electric boiling water reactor for this plant is based upon proven technological concepts developed during the development, design, and operation of numerous similar reactors. The Atomic Energy Commission (AEC), in reviewing the Hatch Nuclear Plant - Unit 1 (HNP-1) docket at the Construction Permit stage, identified several areas where further efforts were required to more definitely assure safe operation of this plant.

This appendix discusses each of these areas of concern, indicating the planned or accomplished resolution. The discussion has been subdivided as follows:

A. *Items cited in the HNP-1 Advisory Committee on Reactor Safeguards (ACRS) Construction Permit Letter (section J.2).*

B. *Items identified by the AEC Regulatory Staff as requiring additional studies or design details (section J.3).*

C. *Items cited in other related ACRS Construction and Operating Permit Letters on other dockets prior to the HNP-1 Construction Permit (section J.4).*

J.2 ITEMS CITED IN THE HNP-1 ACRS CONSTRUCTION PERMIT LETTER

J.2.1 INTRODUCTION

Hatch Nuclear Plant-Unit 1 (HNP-1) had one Atomic Energy Commission - Advisory Committee on Reactor Safeguards (AEC-ACRS) letter associated with its docket. The letter was issued on May 15, 1969, as a regular event in the course of a construction permit application process.

"At its 109th meeting, May 8-10, 1969, the ACRS completed its review of the application by Georgia Power Company for authorization to construct the Edwin I. Hatch Nuclear Plant. This project was considered at the 108th ACRS meeting, April 10-12, 1969, a special meeting on May 2, 1969, and at a Subcommittee meeting and site visit on March 27 and 28, 1969. During its review, the Committee had the benefit of discussions with representatives of the Georgia Power Company, General Electric Company, Southern Services, Inc., Bechtel Corporation, the AEC Regulatory Staff, and their consultants."

This letter contained several items of concern to the ACRS. These concerns and their resolutions are presented in this section.

J.2.2 ITEMS CITED IN ACRS REPORTS PRIOR TO THE HNP-1 REPORT

J.2.2.1 Concern

"Several problems unique to boiling water reactors have been identified by the Regulatory Staff and the ACRS and cited in previous ACRS reports. The Committee believes that resolution of these items should apply equally to the Hatch Plant."

J.2.2.2 Resolution

These items are discussed in section J.4 of this appendix.

J.2.3 INSERVICE INSPECTION

J.2.3.1 Concern

"'The Committee continues to reiterate its interest in an appropriate program for inservice inspection of the reactor primary system. The applicant is conducting a study to establish a more vigorous inservice inspection program than that initially proposed and to specify design provisions to facilitate the new program, particularly with regard to access to the primary system. The applicant stated he will give careful attention to the provisions of the United States of America Standards Institute draft standard on inservice inspection in this study, and he will complete the study within six to nine months. The Regulatory Staff should review this program and should report the results of its review to the Committee."

J.2.3.2 <u>Resolution</u>

The results of this study were filed with the AEC in February 1970 as supplementary information to the Preliminary Safety Analysis Report (PSAR). The inservice inspection program is included in the Final Safety Analysis Report (FSAR) as appendix H.

J.2.4 REACTOR INSTRUMENTATION

J.2.4.1 <u>Concern</u>

"In the area of reactor instrumentation, the Committee believes:

A. The rod block monitor system can perform an important safety, as well as operational, function and that incorporation of such a system or its equivalent is necessary.

B. There should be suitable provisions to ensure that low-pressure core cooling capability will be available before the auto-relief depressurization can be initiated.

C. The flux scram point should be automatically reduced to an appropriate level as the reactor recirculation flow is reduced below the normal full-power flow.

D. The systems which perform these functions should be built to meet appropriate protection system criteria. The criteria to be used for each system should be established on a basis acceptable to the Regulatory Staff."

J.2.4.2 <u>Resolution</u>

The following paragraphs summarize responses given in PSAR amendment 7 dated June 1969 and provide appropriate FSAR references.

A. The rod block monitor system design was changed to meet the intent of the concern expressed in A. of J.2.4.l. Refer to subsection 7.5.8.

B. An interlock was added in the core standby cooling system (CSCS) initiation design such that adequate low-pressure cooling must be available before auto-relief depressurization is initiated. Refer to paragraph 7.4.3.3.

C. Design provisions were made to automatically reduce the flux scram level according to recirculation flow. Refer to subsection 7.5.7.

D. The above systems are designed in accordance with appropriate protection system criteria.

J.2.5 COMMON MODE FAILURE AND FAILURE TO SCRAM

J.2.5.1 Concern

"The Committee believes that, for transients having a high probability of occurrence, and for which action of a protection system or other engineered safety feature is vital to the public health and safety, an exceedingly high probability of successful action is needed. Common failure modes must be considered in ascertaining an acceptable level of protection. In the event of a turbine trip, reliance is placed on prompt control rod scram to prevent large rises in primary system pressure. The applicant and his contractors have devoted considerable effort to providing a reliable protective system. However, systematic failures due to improper design, operation, or maintenance could obviate the scram reliability. The Committee recommends that a study be made of further means of preventing common failure modes from negating scram action, and of design features to make tolerable the consequences of failure to scram during anticipated transients."

J.2.5.2 Resolution - Common Mode Failure

General Electric Topical Report NEDO-10189, "An Analysis of Functional Common Mode Failures in General Electric Boiling Water Reactor Protection Systems," was filed with the AEC in October 1970 in response to the common mode failure concern.

The report provides a comprehensive evaluation of the safety response of HNP-1 and other General Electric boiling water reactors (GE-BWRs) to a wide range of abnormal operational transients and postulated accidents, assuming that individual protection system input signals are blocked by an unidentified common mode failure. A total of 128 event analyses was performed in this study, and it was found in each case that a diverse means of sensing the event and initiating protective action, independent from the common mode failure, is provided in the design. The major portions of the diverse safety actions are completely automatic. In those nonautomatic actions, operator control was found to be adequate and effective in establishing safe plant response.

J.2.5.3 Resolution - Failure to Scram

Results of this analysis appear in appendix L.

J.2.6 TID-14844 SOURCE TERM FOR ENGINEERED SAFETY FEATURE DESIGN BASIS

J.2.6.1 Concern

"For purposes of design of the engineered safety features, the applicant has proposed using a fission-product source term smaller than that suggested in TID-14844, and a treatment of this source within the containment different from that recommended in the same document. The Committee believes that the assumptions of TID-14844 should be used as a design basis for the engineered safety features of the Hatch plant unless and until the use of a different set of assumptions has been justified to the satisfaction of the Regulatory Staff and the ACRS."

J.2.6.2 Resolution

The assumptions of TID-14844 were used as a design basis for the engineered safety features for Plant Hatch. Refer to PSAR amendment 7, submitted in June 1969, and FSAR section 14.5.

J.2.7 CORE STANDBY COOLING SYSTEMS POST-ACCIDENT INTEGRITY

J.2.7.1 Concern

"The Committee reiterates its concern that the post-accident cooling system retain its integrity throughout the course of an accident and the subsequent cooling period. The applicant should review the effects of coolant temperature, pH, radioactivity, corrosive materials from the core or other parts of the containment (including stored chemicals), and potentially abrasive slurries. Degeneration of components such as filters, pump impellers, and seals by any of these mechanisms should be reviewed. Particular attention should be paid to potential problems arising from the use of dissimilar metals in these systems."

J.2.7.2 Resolution

The design criteria for the core standby cooling systems were stated in PSAR amendment 7 filed in June 1969. These criteria are being followed in the specification of components and materials.

J.2.8 CORE STANDBY COOLING SYSTEMS SUCTION PIPING DESIGN AND LEAK DETECTION CAPABILITY

J.2.8.1 Concern

"Engineered safety systems that are required to recirculate water after a loss-of-coolant accident should be designed so that a gross system leak will not result in critical loss of recirculation or in a loss of isolation capability. The Committee believes that exception to this general rule may be made in respect to a very short run of pipe from the torus to the first valve if extremely conservative design of the pipe (and its connection to the torus) is used and suitable remote operability of the valve is provided. The design of these systems also should provide adequate leak detection and surveillance capability."

J.2.8.2 Resolution

PSAR amendment 7, filed in June 1969, contains information concerning:

- *The short run of piping to the first valve.*
- *The conservative design of this piping.*
- *The remote operability of the first valve.*
- *Leak detection and surveillance capability.*

Information concerning these features is also included in the FSAR in sections 4.10, 7.4, and A.3.

J.2.9 ASEISMIC DESIGN OF SUPPORTS

J.2.9.1 Concern

"The applicant has agreed to supply, for review by the Regulatory Staff, preliminary details concerning aseismic design of the supports for the torus and associated piping and of the personnel lock prior to installation of these components."

J.2.9.2 Resolution

Aseismic design details of the supports for the drywell, torus, and personnel lock were filed with the AEC by letter dated December 1, 1969, and supplementary information to the PSAR dated August 28, 1970.

J.2.10 HYDROGEN GENERATION

J.2.10.1 Concern

"Studies are continuing on the possible effects of radiolysis of water in the unlikely event of a loss-of-coolant accident. The Committee believes the applicant should evaluate all problems which may arise from hydrogen generation, including various levels of Zircaloy-water reactions which could occur if the effectiveness of the emergency core cooling system were significantly less than that predicted. The matter should be resolved between the applicant and the AEC Regulatory Staff."

J.2.10.2 Resolution

In order to eliminate the possibility of a flammable gas mixture resulting from a Zircaloy-water reaction, a primary containment nitrogen inerting system was incorporated in the HNP-1 plant design. This system is discussed in FSAR paragraph 5.2.2.9.

Studies of the production of hydrogen and oxygen by radiolysis and methods for controlling either the hydrogen or oxygen concentration in the primary containment are continuing.

The following experimental programs were undertaken by GE to better resolve the concerns relative to the hydrogen production by coolant radiolysis:

- *Operating reactor shutdown tests.*
- *Simulated BWR radiolysis tests at Oak Ridge National Laboratory.*

Information on the results of these tests and their relation to a large BWR can be found in Amendment 23 to the Dresden Nuclear Power Station Unit 3.

J.2.11 MAIN STEAM LINE INTEGRITY

J.2.11.1 Concern

"The applicant proposes acceptable standards of design, fabrication, and inspection of the steam lines downstream of the second isolation valve. The Committee understands that a simplified dynamic analysis of the turbine building will be made to determine the displacements and forces transmitted to the main steam piping supports in the event of an Operating Basis Earthquake."

J.2.11.2 Resolution

The resolution was filed with the AEC in June 1969 as amendment 7 to the PSAR. Refer to sections A.3 and H.2.

J.3 ITEMS IDENTIFIED BY THE AEC REGULATORY STAFF AS REQUIRING ADDITIONAL STUDIES OR DESIGN DETAILS

During the course of the construction permit application review, the Atomic Energy Commission (AEC) Regulatory Staff identified a number of specific items requiring additional studies or design details and requested that further information be provided prior to the operating license review. Those items identified by both the Regulatory Staff and the Advisory Committee on Reactor Safeguards (ACRS) are discussed in section J.2. Those items identified only by the Regulatory Staff are discussed in this section.

J.3.1 ADDITIONAL STRUCTURAL DETAILS

J.3.1.1 Concern

"Provide additional details of the intake structure foundation design and the main stack foundation design."

J.3.1.2 Resolution

The intake structure foundation design details and evaluation and the main stack foundation design details and evaluation were filed with the AEC in August 1970 and March 1971, respectively, as supplementary information to the Preliminary Safety Analysis Report (PSAR).

J.3.2 FINAL ENVIRONMENTAL MONITORING PROGRAM

J.3.2.1 Concern

"Provide additional details of the final environmental monitoring program."

J.3.2.2 Resolution

The environmental monitoring program is discussed in section 2.6 and in the environmental Technical Specifications.

J.3.3 CORE PERFORMANCE WITH ONE RECIRCULATION PUMP

J.3.3.1 Concern

"Testing with one pump operation with the equalized line closed will be conducted at other BWR plants during their startup in addition to and prior to the tests to be conducted on Hatch. These tests will verify the plant response predictions and show that the thermal and hydraulic safety margins are satisfactory ...."

"Only gross core flow measurements are contemplated since plant design does not permit more detailed flow measurement."

J.3.3.2 Resolution

The test program for resolution of this concern was conducted, and present Hatch Technical Specifications allow for single-loop operation.

J.3.4 STANDBY LIQUID CONTROL CALCULATIONS

J.3.4.1 Concern

"In order to verify the accuracy of the calculations experimental data showing the reactivity effect of a boron solution in a reactor system will be analyzed. This analysis will be compared to calculated reactivity by adopting the methods used for Hatch to the conditions of the experimental data."

J.3.4.2 Resolution

Existing experimental pressurized water reactor data were used to verify the accuracy of the General Electric-APED analytical model for predicting the shutdown capabilities for the standby liquid control system. Paragraph 3.8.4.1 shows this verification.

J.3.5 PLANT SHUTDOWN FROM OUTSIDE CONTROL ROOM

J.3.5.1 Concern

"Actions which could be taken by reactor operators to bring the plant to a safe and orderly cold shutdown under normal plant conditions were reviewed, assuming that access to the main control room was postulated to be limited. One possible course of action was described. Detailed operating

instructions in the event of postulated evacuation of the main control room were prepared during the preoperational period."

J.3.5.2 Resolution

Detailed instructions were made available during the preoperational phase of the plant program.

J.3.6 FUEL POOL - RESIDUAL HEAT REMOVAL (RHR) SYSTEM INTERTIE

J.3.6.1 Concern

"Detailed operating procedures for the RHR system were reviewed, with regard to the intertie with the fuel pool cooling system."

J.3.6.2 Resolution

Operating procedures for the RHR system intertie were established during the preoperational test.

J.3.7 REVIEW OF SAFETY FEATURE ANALYSIS

J.3.7.1 Concern

"Engineering analyses associated with engineered safety features and design basis accident analysis were reviewed (e.g., control room shielding and air-conditioning system, standby gas treatment system (SGTS), etc.)."

J.3.7.2 Resolution

The SGTS is discussed in section 5.3. The main control room environmental system is discussed in section 10.17. Main control room shielding is discussed in section 12.7.

The design basis for these systems and other engineered safety features is presented in section 14.5.

J.3.8 RADIATION DETECTION IN PLANT SERVICE WATER (PSW) SYSTEM

J.3.8.1 Concern

"The design of the portions of the PSW system which service components in the reactor building were reviewed to ensure that adequate instrumentation was included to detect radiation during plant operation and permit isolation of the system."

J.3.8.2 Resolution

The instrumentation provided to detect radiation in the PSW system is discussed in subsection 7.12.4, Process Liquid Radiation Monitors.

J.3.9 NUMBER OF OPERATORS PER SHIFT

J.3.9.1 Concern

"Justify the use of four operators per shift."

J.3.9.2 Resolution

The number of operating personnel per shift was established using as a basis the criteria used to establish the shift size for the operation of Georgia Power Company's complex fossil generating plants. These criteria have proven successful in operation and should be applicable to the operation of the Edwin I. Hatch Nuclear Plant.

The criteria used for establishing the shift size are as follows:

A. *Provide the necessary personnel trained in the appropriate skills to normally operate the plant and cope with the immediate actions required during abnormal or emergency conditions.*

B. *Provide a complete automatic control system with well laid out control boards which require a minimum of operator attention. Control boards are designed for operation by one operator.*

C. *Provide automatic surveillance of remote equipment with alarm annunciation on deviations from normal.*

D. *Provide automatic data logging functions.*

E. *Provide automatic safe shutdown of the unit should certain variables exceed set limits.*

F. Provide the shift supervisor with the authority, as well as the responsibility on his shift, to take any necessary actions required to safeguard the plant equipment or protect the plant personnel and general public.

Minimum shift requirements are set forth in the Technical Specifications in accordance with NRC requirements.

J.4 ITEMS CITED IN OTHER RELATED ACRS CONSTRUCTION AND OPERATING PERMIT LETTERS PRIOR TO THE HNP-1 LETTER

This section presents a review of applicable items cited in Advisory Committee on Reactor Safeguard (ACRS) reports prior to the Hatch Nuclear Plant-Unit 1 (HNP-1) ACRS report.

J.4.1 EFFECTS OF CLADDING TEMPERATURES AND MATERIALS ON CORE STANDBY COOLING SYSTEM (CSCS) PERFORMANCE

J.4.1.1 Concern

"*One of the areas of ACRS concern is the ability of the boiling water reactor (BWR) CSCS to effectively cool the reactor core following the postulated loss-of-coolant accident (LOCA).*

′In the loss-of-coolant accident, the core spray and flooding systems are required to function effectively under circumstances in which some areas of fuel clad may have attained temperatures higher than those at which such cooling mechanisms have been tested to date. The applicant is conducting tests of these devices at increased temperatures and has reported preliminary results which are promising. The Committee again urges that these tests be extended to temperatures as high as practicable. The use of stainless steel in these tests for simulation of the zircaloy appears suitable, but some corroborating tests employing zircaloy should be included.′ (ACRS Report on Vermont Yankee Nuclear Power Station ACRS Letter June 15, 1967)

This quote is substantially the same as an earlier one for the Browns Ferry Nuclear Plant Units 1 and 2 except that flooding systems were not specifically included in the earlier statement."

J.4.1.2 Resolution

The general approach adopted to resolve this ACRS concern was to develop high-temperature zircaloy-clad electrically heated fuel rod simulators and to use these in full-size bundle tests under both spray and flooding modes. The test conditions were chosen to duplicate as nearly as possible the boundary conditions of initial temperature, coolant flowrate, and power transients representative of the multitude of tests previously performed with the stainless steel-clad heaters. A second phase of the testing was to investigate emergency core cooling effectiveness at peak cladding temperatures in excess of 2500°F, to the highest temperatures the heaters would permit.

Several emergency core cooling effectiveness tests were conducted by General Electric (GE)-APED under a subcontract to the Idaho Nuclear Corporation. This AEC-funded program is the Full Length Emergency Cooling Heat Transfer Program (Subcontract S-7044 under Contract AT(10-1)-1230 between United States Atomic Energy Commission and Idaho Nuclear Corporation). These tests were performed using electrically internally heated (calrod type), 49-rod, full-size bundles. To date the program included four bundles with stainless steel-cladding heaters and three bundles with production zircaloy-cladding heaters.
In addition, another full-size zircaloy bundle was tested under the GE-APED development program.

The test results of the programs described above were submitted in July 1970 to the AEC as a GE Topical Report.[1]

J.4.2 EFFECTS OF FUEL BUNDLE FLOW BLOCKAGE

J.4.2.1 Concern

"′*The applicant considers the possibility of melting and subsequent disintegration of a portion of a fuel assembly, by inlet coolant orifice blockage or by other means, to be remote. However, the resulting effects in terms of fission product release, local high pressure production, and possible initiation of failure in adjacent fuel elements are not well known. Information should be developed to show that such an incident will not lead to unacceptable conditions.′ (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, AEC Docket No. 50-259 and 50-260). The Committee believes that these matters are of significance for all large water-cooled power reactors, and warrant careful attention.*"

J.4.2.2 Resolution

A complete flow blockage at full-power conditions, the most severe combination of conditions, will not result in:

- *An incident capable of initiating failure in adjacent assemblies.*
- *Local high pressure production.*
- *Offsite doses exceeding those guidelines set forth in 10 CFR 20.*

Even though it is possible for minor blockages to occur by small objects entering the fuel bundle and affecting the life of the fuel, it is unlikely that a blockage which would induce a significant flow reduction will occur. A fuel assembly is capable of withstanding very severe blockages before losing adequate cooling. Flow blockages greater than approximately 90 percent must result before critical heat flux first occurs.

The only mechanism capable of causing such flow blockages is that induced by a foreign object. Fragmentation, crudding, or fuel swelling cannot cause significant flow blockages.

Detailed results of the studies to resolve this concern were submitted in May 1970 to the AEC as a Topical Report.[2]

J.4.3 VERIFICATION OF FUEL DAMAGE LIMIT CRITERION

J.4.3.1 Concern

"′A linear heat generation rate of 28 kW/ft is used by the applicant as a fuel element damage limit. Experimental verification of this criterion is incomplete, and the applicant plans to conduct additional tests. The Committee recommends that such tests include heat generation rates in excess of those calculated for the worst anticipated transient and fuel burnups comparable to the maximum expected in the reactor.′ (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, AEC Docket No. 50-259 and 50-260). The Committee believes that these matters are of significance for all large water-cooled power reactors and warrant careful attention."

J.4.3.2 Resolution

A GE Topical Report[3] submitted to the AEC in June 1970 presents a review of experience and development data demonstrating that:

A. *GE-BWR Zircaloy-clad UO_2 pellet fuel can be operated with a high degree of integrity at the proposed power (kW/ft) and exposure (MWd/MT).*

B. *There is sufficient margin between the steady-state operating condition (operating limits) and the damage limit linear heat generation rate to accommodate the highest anticipated reactor transient power without the occurrence of fuel damage.*

C. *The basic models employed in the design of the GE-BWR Zircaloy-clad UO_2 pellet fuel embody a substantial degree of conservation, confirming the inherent conservatism in the fuel design.*

J.4.4 EFFECTS OF FUEL FAILURE ON CSCS PERFORMANCE

J.4.4.1 Concern

"Analysis indicates that a large fraction of the reactor fuel elements may be expected to fail in certain loss-of-coolant accidents. The applicant states that the principal mode of failure is expected to be by localized perforation of the clad, and that damage within the fuel assembly of such nature or extent as to interfere with heat removal sufficiently to cause clad melting would not occur. The Committee believes that additional evidence, both analytical and experimental, is needed and should be obtained to demonstrate that this model is adequately conservative for the power density and fuel burnup proposed." (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, Docket Nos. 50-259 and 59-260)

J.4.4.2 <u>Resolution</u>

The specific approach taken to resolve this ACRS concern was to investigate the various parameters affecting deformation of the cladding (i.e., swelling or ballooning). These investigations included single-rod experiments (scoping type), multi-rod experiments (interaction), multi-rod core cooling experiments (emergency core cooling system (ECCS) performance), and bundle analytical predicted performance.

The boundary conditions chosen for these experiments and calculations included the range of parameters expected in a BWR fuel bundle following a postulated LOCA. The primary factors investigated included heating rate of cladding, the internal gas pressure due to fission product release from the UO_2 fuel, and the effect of irradiation.

The investigations pertinent to this ACRS concern of fuel failure following a postulated LOCA were conducted by Oak Ridge National Laboratory, Combustion Engineering, Babcock & Wilcox, Westinghouse, GE-Atomic Power Equipment Department, GE-Nuclear Systems Programs, Idaho Nuclear Corporation, and Battelle Columbus Laboratories.

The results of this investigation indicate that for the postulated LOCA, the BWR ECCS heat transfer effectiveness is not sufficiently impaired by cladding deformation to result in melting of the fuel rod cladding. The potential cladding deformation is primarily due to the rapid increase in the cladding temperature above normal and the stresses in the cladding due to the internal fission gas pressure. The primary reasons why these distortions do not significantly affect the heat transfer effectiveness are:

A. *The design of the BWR ECCS precludes the cladding from being at an over-temperature condition for a long period of time (less than 3 1/2 min for the recirculation line break).*

B. *The reactor vessel configuration (jet pump design) and the recirculation pump characteristics preclude the cladding temperature from being at high values at the initiation of the ECCS (peak cladding temperature is approximately 1300° to 1500°F at the end of the blowdown).*

C. *The effective gross deformation (i.e., swelling) has been shown to be limited to a short length of any fuel rod (approximately 2 in.).*

D. *Perforations within a fuel bundle do not cause a propagation of fuel cladding failure to other rods within the bundle. Furthermore, the axial distribution of fuel rod failures (swelling) within a bundle results in partial local flow area blockage, not complete blockage at one elevation or horizontal plane.*

E. *The effect of irradiation has been shown to result in a significant reduction in the total amount of cladding strain (swelling) and a slight reduction in the failure temperature.*

F. *The effect of partial coolant flow area blockage has been demonstrated experimentally to be beneficial in the heat transfer effectiveness of the flooding mechanism at local blockages (one third of bundle) up to 75 percent.*

G. *The effect of complete coolant flow area blockages up to 90 percent has been shown analytically to not impair the flooding effectiveness allowing fuel rod cladding melting.*

H. *The effect of bundle distortion on the overall heat transfer effectiveness of spray cooling was experimentally shown to be minor using a full-size, Zircaloy-clad, internally pressurized 49-rod bundle under LOCA conditions more severe than those expected in an actual reactor.*

The results of the program to resolve this concern were submitted in August 1970 to the AEC as a Topical Report.[4]

J.4.5 MAIN STEAM LINE ISOLATION VALVE TESTING UNDER SIMULATED ACCIDENT CONDITIONS

J.4.5.1 Concern

"Steam line isolation valves are provided which constitute an important safeguard in the event of failure of a steam line external to the containment. One or more valves identical to these will be tested under simulated accident conditions prior to a request for an operating license." (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, AEC Docket No. 50-259 and 50-260)

J.4.5.2 Resolution

GE implemented a program to test a full-size main steam line isolation valve under simulated accident conditions. This research and development program involved testing of valves on a small scale to permit evaluation of hydrodynamics of the blowdown under prototypical conditions and testing of a valve essentially identical in design to those to be used in this plant simulating as closely as feasible the accident conditions.

The testing programs were successfully completed and reported in a GE Topical Report[5] *submitted to the AEC in March 1969. Analysis of the accident event is discussed in a GE Topical Report*[6] *submitted to the AEC in October 1969.*

J.4.6 DIVERSIFICATION OF THE CSCS INITIATION SIGNALS

J.4.6.1 Concern

"Also, he will explore further possibilities for improvement, particularly by diversification, of the instrumentation that initiates emergency core cooling, to provide additional assurance against delay of this vital function." (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, AEC Docket No. 50-259 and 50-260)

J.4.6.2 Resolution

The preliminary design of sensors of the CSCS equipment consisted of a reactor vessel low-water signal from either of two independent instrumentation sources to activate the pumping equipment. Further studies were conducted to ascertain whether reliability could be improved by utilizing alternate or improved sensors. As a result of these studies, instrumentation detecting high pressure in the drywell was incorporated, in addition to the reactor low-water level instruments, to actuate reactor core spray cooling, high-pressure coolant injection (HPCI), low-pressure coolant injection (LPCI), and the standby diesel generator systems.

J.4.7 MISORIENTATION OF FUEL ASSEMBLIES

J.4.7.1 Concern

"Operation with a fuel assembly having an improper angular orientation could result in local thermal conditions that exceed by a substantial margin the design thermal operating limits. The applicant stated that he is continuing to investigate more positive means for precluding possible misorientation of fuel assemblies." (Browns Ferry Units 1 and 2, ACRS Letter, March 14, 1967, AEC Docket No. 50-259 and 50-260)

J.4.7.2 Resolution

Operation with a misoriented fuel assembly would be an economic rather than a safety concern. Analyses have shown that less than 10 fuel rods in a misoriented assembly would experience an MCHFR less than 1.9. Under normal operating conditions, these 10 fuel rods would, even in the peak power position, remain at an MCHFR greater than 1.0 and peak linear heat generation rate less than 28 kW/ft.

Studies into means of precluding possible fuel misorientation were completed. It is concluded that the present method of procedural controls is the most desirable of the alternatives. Fuel handling operations at operating GE-BWRs have shown this to be an efficient, effective method.

Various mechanical devices to prevent inserting a misoriented fuel assembly were also studied and eventually discarded. These devices tended to provide greater potentials for fuel damage during loading and storage operations than the misorientation they were designed to prevent.

Visual identification has been successfully used in all BWRs operated to date to provide assurance of fuel location and orientation. Photos taken of the KRB core after the initial fuel loading clearly showed four different means of identifying a misoriented fuel assembly; they are:

- *All the assembly numbers point towards the center of the cell.*
- *The spring clip assemblies all face the control rod.*
- *The lugs on the handles point towards the control rods.*

- *There is cell-to-cell replication.*

Experience has shown that the distinguishing features will be visible during the design lifetime of the fuel. In all cases, fueling procedures require that the fuel assembly number be verified. As a result of this study and the accumulated fuel handling experience, no further work with respect to providing an alternate means of preventing fuel assembly misorientation is planned. Refer to chapter 3.0 for further details.

J.4.8 HPCI SYSTEM - DEPRESSURIZATION CAPABILITY

J.4.8.1 Concern

"The film condensation coefficient used to predict the depressurization performance of the HPCI system is based on extrapolation of available heat transfer data. Additional experiments or other supporting studies are needed to confirm the effectiveness of the HPCI system, and the results should be reviewed by the Regulatory Staff." (Peach Bottom, ACRS Letter, March 12, 1967, AEC Docket No. 50-277 and 50-278)

J.4.8.2 Resolution

The function of HPCI is to provide coolant makeup to the reactor vessel to keep the reactor core covered and cooled for small system breaks. The HPCI also depressurizes the reactor so that the LPCI system or the reactor core spray system in the CSCS network can become effective for somewhat larger breaks than can be handled entirely by HPCI system inventory makeup. An analytical model based upon solution to the mass and energy balances for the system assuming thermodynamic equilibrium, is used to predict the depressurization characteristics due to HPCI system operation. Because equilibrium does not actually exist, a calculated "mixing efficiency" is used to represent how nearly the injected subcooled water is raised to the temperature of the reactor vessel fluids.

Engineering tests were conducted in which subcooled water was injected into a constant volume, high-pressure steam water system designed to simulate reactor conditions and geometry. Depressurization rate, inlet, and fluid temperatures were measured. An overall mixing efficiency was evaluated. A sufficient range of variables were included in the tests such as to determine a mixing efficiency for each reactor primary system.

The results and successful completion of this test program were submitted in June 1969 to the AEC in a GE Topical Report.[7]

J.4.9 PLANT STARTUP PROGRAM

J.4.9.1 Concern

"As in the case of the Browns Ferry units, a careful startup program will be required. If the startup program or additional information on fuel behavior fail to confirm adequately the design basis, system modifications or restrictions on operation may be appropriate." (Peach Bottom Units 2 and 3, ACRS Letter, March 12, 1967, AEC Docket No. 50-277 and 50-278)

J.4.9.2 Resolution

The extent and scope of the startup program for this plant will reflect consideration appropriate for the size of the reactor and the thermal characteristics, service or transient conditions which might affect fuel integrity, reactor control and response characteristics, and functional performance of safeguard features contained in the plant design.

In particular, extensive surveys of reactor core power distribution will be performed during the initial approach to the reactor power. It is expected that this program will demonstrate that power distributions, as good as or better than predicted, will be realized. Appropriate steps will be taken to ensure that safety margins are maintained under operational conditions.

A step-by-step power 1evel approach to 2436 MWt is p1anned.

A GE Topica1 Report[8] was submitted in February 1969 to the AEC on a summary of results obtained from a typical startup and power test program for a GE-BWR.

Refer to chapter 13.0 for further detai1s of the startup program.

REFERENCES

1. *Liffengren, D. J., "Effects of Cladding Temperature and Material on ECCS Performance," General Electric Company, NEDO-10179, June 1970.*

2. *Scatena, G. J., "Consequences of a Postulated Flow Blockage Incident in a Boiling Water Reactor," General Electric Company, NED0-10174, May 1970.*

3. *"Current State of Knowledge of High Performance BWR Ziracloy Clad UO_2 Fuel," General Electric Company, NEDO-10173, May 1970.*

4. *Liffengren, D. J., "Effects of Fuel Rod Failure on ECCS Performance," General Electric Company, NEDO-10208, August 1970.*

5. *Rockwell, D. A., and Van Zylstra, E. H., "Design and Performance of GE-BWR Main Steam Line Isolation Valves," General Electric Company, APED-5750, March 1969.*

6. *Rockwell, D. A., "Consequences of a Main Steam Line Break for a GE-BWR," General Electric Company, NEDO-10045, October 1969.*

7. *Rogers, A. E., and Torbeck, J. E., "Depressurization Performance of the GE-BWR-HPCIS," General Electric Company, APED-5447, June 1969.*

8. *"Summary of Results Obtained from a Typical Start-Up and Power Test Program for a GE-BWR," General Electric Company, APED-5698, February 1969.*

APPENDIX K

CONTAINMENT DESIGN INFORMATION

K.1 INTRODUCTION

This appendix provides a technical synopsis of the design basis, configuration, loadings, loading combinations, and initial test of the primary containment. Additional containment design information is presented in supplement KA.

K.2 DESIGN BASIS

K.2.1 GENERAL

The primary containment consists of the drywell, vents, and steam suppression chamber (torus). Chicago Bridge and Iron Company (CB&I) designed, fabricated, furnished, installed, tested, and painted the primary containment vessels and their appurtenances, in accordance with procedures, drawings, and specifications of Bechtel.

The design is based on the spatial layout of components required for system operation. The vessels are designed to be capable of sustaining the specified loads which are dead loads, live loads, pressures, thermal loads, seismic loads, etc.

The information in this report pertaining to the detailed design of the primary containment is taken from CB&I's Certified Stress Report, which is on file at the plant site.

K.2.2 CODES AND STANDARDS

As defined in section 12.3, the primary containment vessels are Seismic Class 1 structures. The design, materials, fabrication, erection, inspection, and testing of the vessels conform to the following codes.

The vessels are subject to the requirements of the American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1968 edition and all addenda effective as of June 30, 1968, including code cases 1330-1, 1177-5, and 1431. As defined by this code, the vessels are Class B. The completed vessels are thus stamped with the ASME Boiler and Pressure Vessel Code stamp for nuclear vessels.

The elements not governed by the ASME Code are subjected to the requirements of the "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," of the American Institute of Steel Construction (1963). These elements include the jet deflectors, supports, platforms, ladders, and accessories.

All piping is subject to the requirements of the Specifications of the United States of America Standards Institute Code for Pressure Piping B31.1.0, 1967 Edition.

All connections with concrete supports were based on design criteria as set forth in the American Concrete Institute (ACI), "Standard Building Code Requirements for Reinforced Concrete," ACI 318-63.

K.2.3 MATERIALS

The vessels, vents, welding pads, and all pressure boundary plates are made of carbon steel, ASME SA 516, Grade 70 made to SA 300 except that the Charpy V-notch impact materials tests were conducted as specified in ASME, Section III, N-331.2, and ASME SA 370 with a

20-ft-lb impact as average for each set of plates in accordance with ASME, Section III, Article 12. The test temperature was 0°F. The service metal temperature was specified at 30°F.

Welded carbon steel pipe conforms to American Society for Testing Materials (ASTM) A 155, Grade KC 70, Class 1, with the plate material conforming to SA 516, Grade 70. After heat treatment, impact tests were made on representative specimens. Table K.2-1 summarizes the materials used in the primary containment. Elements not subject to the scope of the ASME Code, Section III, conform to the applicable ASTM specifications.

K.2.4 CLEANING AND PAINTING

After cleaning all surfaces as per detailed instructions, the interior surface of the vessels and exterior surfaces above el 201 ft 4 in. were primed with an inorganic zinc coating. The interior surfaces of the drywell and vent lines and the exterior surfaces above el 201 ft 4 in. were finish coated with a modified phenolic epoxy. The interior surface of the torus plate and all other internal components of the torus were left untopcoated. All exterior surfaces below el 201 ft 4 in. were coated with a commercial-grade corrosion resistant paint. All steel surfaces in contact with concrete were left unpainted.

The untopcoated inorganic zinc surfaces in the torus below the waterline were later touched up, as required, with a DBA qualified, 100% solids epoxy, installed by underwater application.

TABLE K.2-1 (SHEET 1 OF 2)

MATERIAL SPECIFICATION FOR THE CONTAINMENT VESSEL

Materials Used for Pressure Parts or Pressure Part Attachments

	ASME or ASTM Specification No. and Grade	Title
Plate	SA 516, Grade 70 made to SA 300 and Section III	Carbon steel of intermediate tensile strength for atmospheric and lower temperature pressure vessel
	SA 240, TYP 304 and 304L	Austenitic stainless steel for Bellows' material
Pipe	SA 333, Grade 1 made to Section III	Seamless carbon steel pipe for low-temperature service
	ASTM A 155 Grade KC 70 C1.1 (Material SA 516, Grade 70)	Welded seamed carbon steel pipe
	SA 106, Grade B	Spray header piping
	SA 312, Type 304	Austenitic seamless stainless-steel pipe
Forging	SA 350, Grade LF1	Coupling
	SA 182, F 304	Threaded plug
Bolting, nuts, pins	SA 198 B8	Threaded stud
	SA 194 G8, G4	Nuts
	SA 320 L43	Bolts

TABLE K.2-1 (SHEET 2 OF 2)

Materials Used for Nonpressure Parts

	ASME or ASTM Specification No. and Grade	Title
Plate	A 514, Grade F (T-1)	Plate
	SA 516, Grade 70	Plate
	A 283, Grade C	Plate penetration cap
	A 36	Plate
Pipe	A 106, Grade B	Spray header pipe
	A 53, Grade B	CRD removal hatch
	A 420, Grade WPL 1	Torus penetration elbow
Structural Shapes	A 36	Monorail
Bolts	A 307	Torus seismic tie pin
	AISI 4140	Head bolts washer hardened to Brinnell harness 248-352
	SA 279, Type 304	Head aligning pin
	SA 479, Type 304	Equipment hatch tiedown assembly
Forging	SA 350, Grade LF1	Centering pin
	SA 105, Grade II	Seismic tie pin
	Other Materials	
	Bronze "lubrite" plates	
	Silicone "Garlock" or equivalent gaskets	

K.3 CONFIGURATION

The principle geometric dimensions of the primary containment are tabulated in table K.3-1 and are shown on drawing nos. S-15265 and S-15290.

A. Drywell Skirt

During erection, the drywell was supported on the circular skirt welded to the bottom portion of the drywell sphere at el 110 ft 6 5/16 in. This cylindrical skirt was anchored to the concrete foundation at el 101 ft 11 1/2 in. and received all erection loads of the drywell. In the skirt an access hatch was provided to facilitate work inside the skirt. The skirt was cut from the drywell after the permanent concrete support was constructed. Thus the drywell was separated from its temporary support. The skirt was left in place and was buried in foundation concrete.

B. Drywell

The drywell is a steel pressure vessel with a spherical lower portion and cylindrical upper portion. The 30-ft 3-in. diameter bolted top closure is made with a double tongue and groove seal which permits periodic checks.

Below el 111 ft 6 in. the drywell is completely encased in reinforced concrete. Shear keys are attached to the drywell as shown in figure K.3-1. They are cylindrical in shape and 8 in. in height. Reinforcement is welded to these shear keys for structural continuity. Between el 111 ft 6 in. and el 114 ft 6 in. the drywell is backed by concrete on the inside and a sand pocket is provided on the outside. Between 114 ft 6 in. and el 200 ft 1 1/2 in. the drywell is enclosed within the structural concrete which also performs the function of shielding against radiation. In this area, there is a nominal 2-in. gap between the vessel and the concrete enclosure. Above el 200 ft 1 1/2 in., the concrete is provided for shielding the drywell and does not backup the drywell for structural purposes.

C. Torus and Vent System

The torus is located below and around the drywell. It is supported by 16 pairs of columns with sliding bases. Four shear ties are provided to resist the forces generated due to earthquake. Drawing no. S-15329 shows the details of a shear tie. Eight vent pipes are located near the base of the drywell and are equally spaced. These pipes penetrate into the suppression chamber and are connected to one common vent header. This vent header has the same shape as the torus and is supported by struts from a ring girder provided in the torus. These struts are hinged at the base and top to allow for differential horizontal movements between the vent header and the torus as shown on drawing no. S-15265.

D. Penetrations

The primary containment penetrations are listed in ***Technical Requirements Manual table T7.0-1 (incorporated by reference into the FSAR)***. Drawing nos. S-15422, S-15520, and S-15665 through S-15667 show the penetrations in plan and elevation. Figures K.3-2 through K.3-5 show the cross-section of the types of typical penetrations.

E. Torus Coatings

A visual inspection is performed during each refueling outage of the torus coating in the area above and below the water line to the extent it is visible from the surface. It is expected that if corrosion effects or loss of coating from peeling occurs, the most likely place would be in the area of the water line.

If during the visual inspection significant corrosion is indicated, an ultrasonic inspection of this area is performed to determine if the thickness of the torus wall meets the minimum wall thickness required.

If it is observed during the surveillance program that excessive coating loss has occurred, the latest developments in the industry are surveyed and will be considered in applying a replacement coating.

These inspections are part of the aging management of the torus structure. (See HNP-2-FSAR subsection 18.3.3 for details of the Protective Coatings Program.)

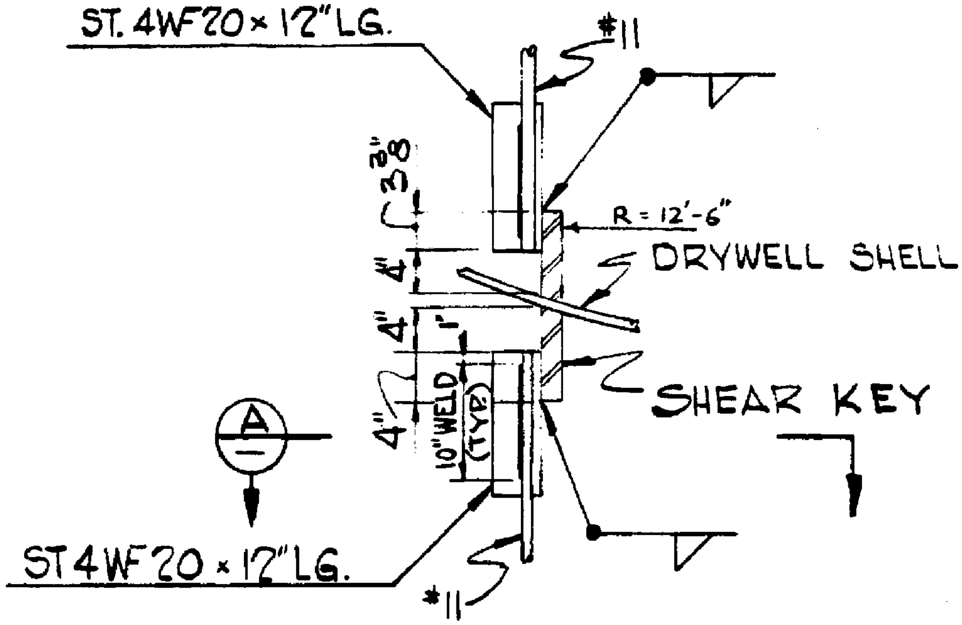
<u>DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR</u>

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

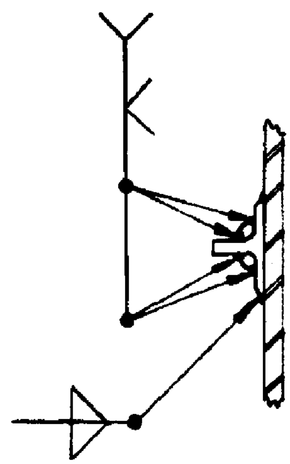
TABLE K.3-1

PRIMARY CONTAINMENT DATA

	Location	Diameter	Plate Thickness
A.	Drywell		
	Skirt (erection support)	16 ft 8 in.	1/2 in.
	Spherical section	65 ft	5/8 to 1 3/8 in.
	Knuckle section	Varies	2 9/16 in.
	Cone	Varies	1 1/4 in.
	Cylindrical section	35 ft 7 in.	3/4 to 1 7/16 in.
	Top head (2:1 elliptical)	30 ft 3 in.	1 7/16 in.
B.	Vent Pipes (8)		
	Internal diameter	5 ft 11 in.	1/4 to 3/8 in.
C.	Pressure-Suppression Chamber (Torus)		
	Torus major diameter	107 ft 1 in.	
	Torus internal diameter	28 ft 1 in.	0.54 to 1 1/16 in.
	Vent header major diameter	107 ft 1 in.	
	Vent header internal diameter	4 ft 6 in.	1/4 in.
	Downcomer pipes internal diameter (80)	1 ft 11 1/2 in.	1/4 and 3/8 in.



SHEAR KEY DETAIL



SECTION A

ACAD 10k0301

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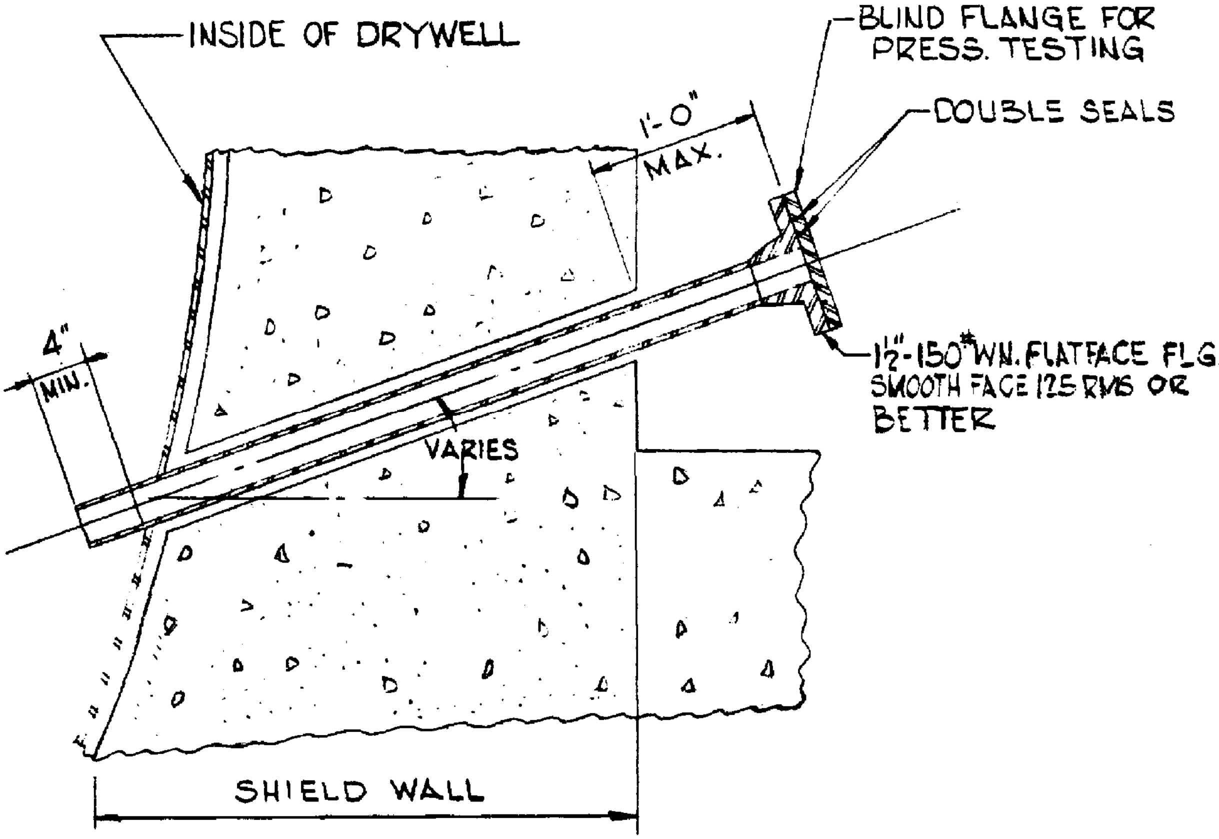
DRYWELL SHEAR KEY DETAILS

FIGURE K.3-1



TYPE 1

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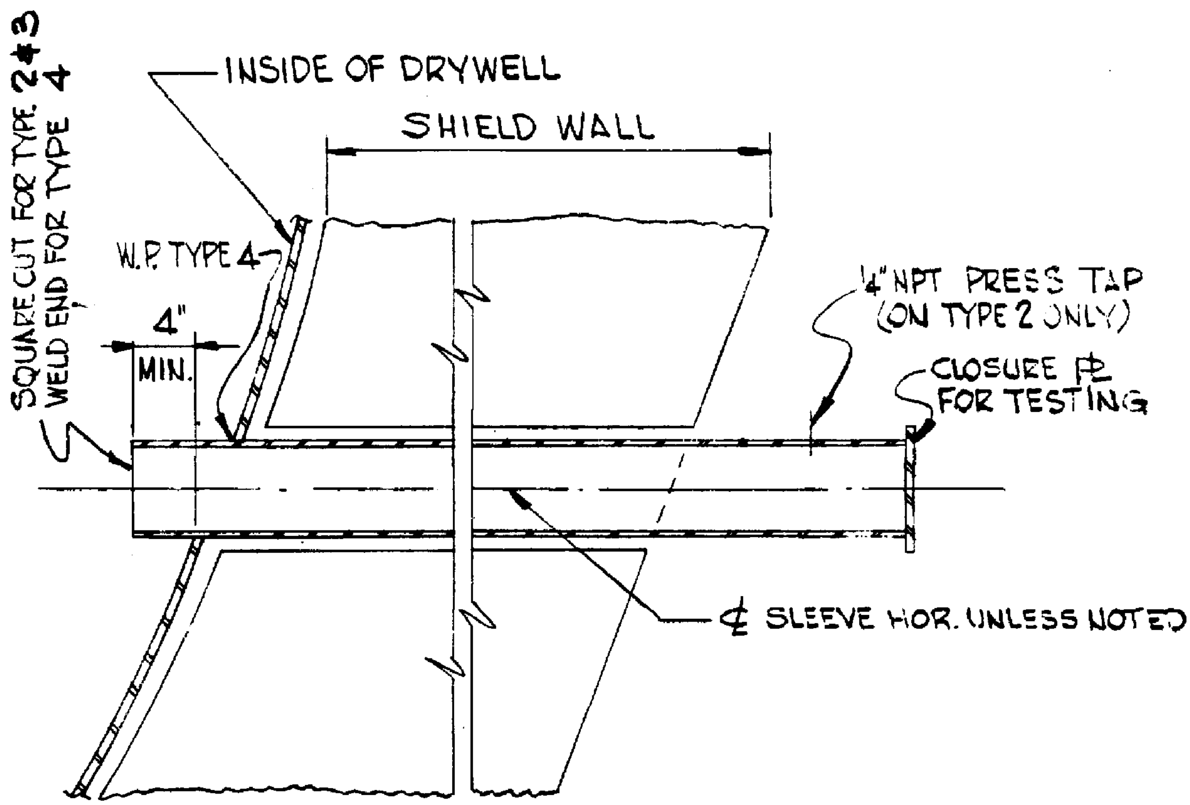
PENETRATION TYPE 1

FIGURE K.3-2



TYPE 2 (AS SHOWN)
TYPE 3 (AS SHOWN & NOTED)
TYPE 4 (AS SHOWN & NOTED)

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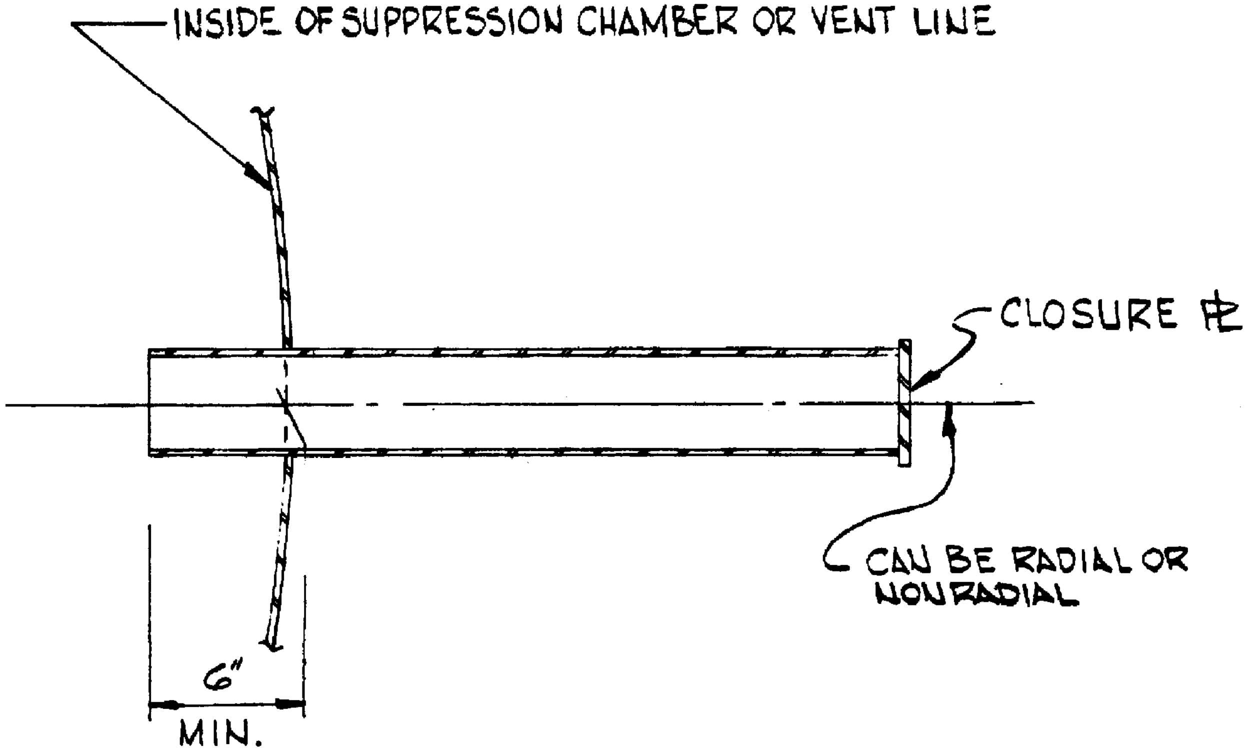
PENETRATION TYPES 2, 3, AND 4

FIGURE K.3-3



TYPE 5

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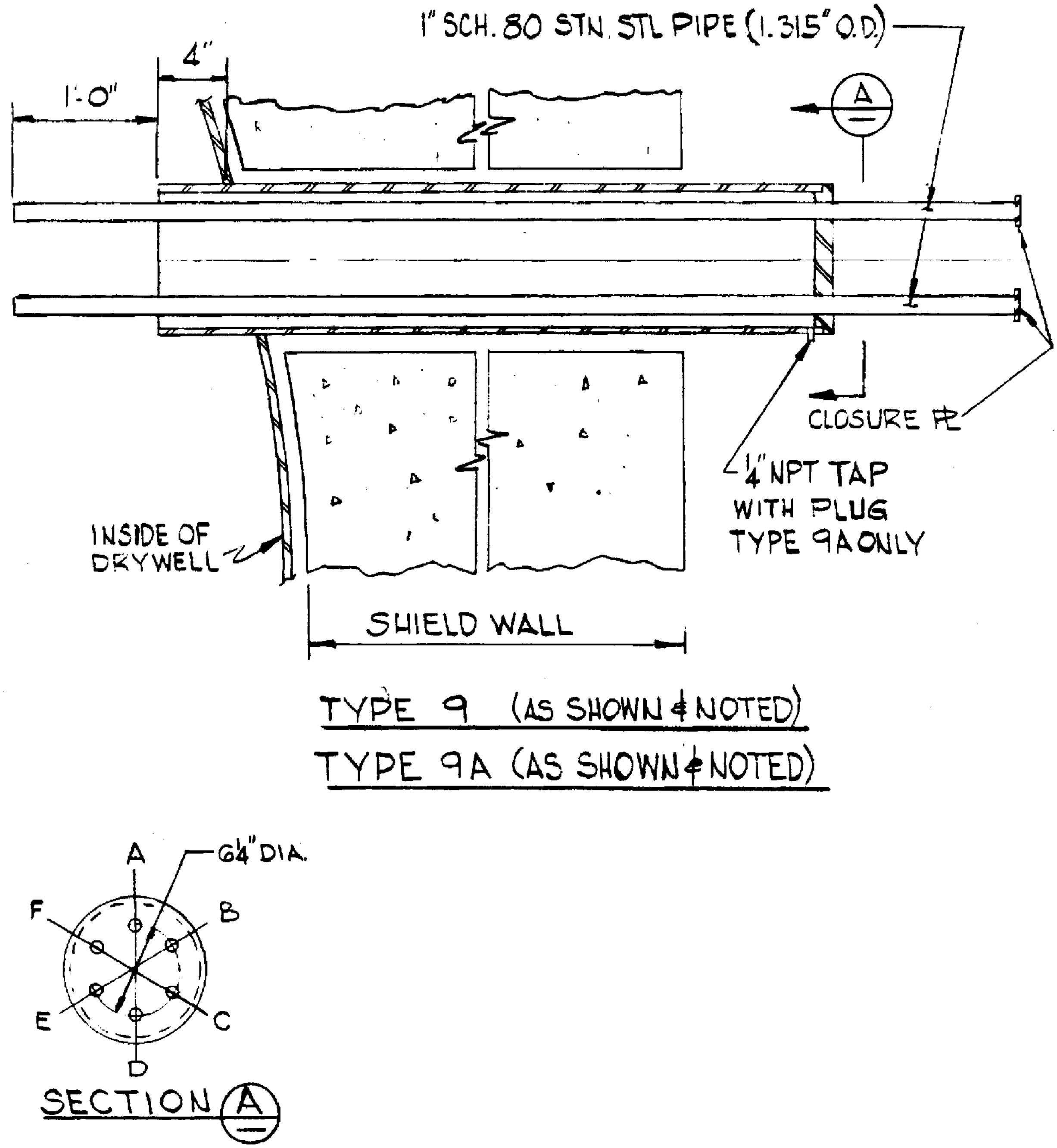
PENETRATION TYPE 5

FIGURE K.3-4



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PENETRATION TYPES 9 AND 9A

FIGURE K.3-5

K.4 DESIGN LOADINGS

The loadings considered in the design of the primary containment are shown in table K.4-1. A description of the loads used in the design are presented in the following paragraphs. All of these possible loads, as well as their combinations, have been taken into consideration and the maximum computed stresses are all within the design specifications, the American Society of Mechanical Engineers (ASME) Boiler and Pressure Code, Section III, or other applicable codes and standards.

K.4.1 WIND LOADS

The drywell was partially exposed prior to complete construction of the reactor building and was designed to withstand the following wind loads on the projected area of the circular shape.

Height Above Foundation (ft)	Wind Load (lb/ft^2)
0-50	23.09
50-Top	36.84

The drywell skirt provided a temporary support for the vessel during construction and was designed for wind forces and erection loads in accordance with the American Institute of Steel Construction Code.

K.4.2 SEISMIC LOADS

As a Seismic Class 1 structure, the drywell was designed to withstand earthquake forces due to the operating basis earthquake (OBE) and design basis earthquake (DBE). The seismic coefficients, for horizontal acceleration and deflection for the drywell in each action are shown in figure K.4-1 and figure K.4-2. A vertical seismic acceleration equal to 5.3% g for OBE and 10% g for DBE was assumed acting simultaneously with the horizontal seismic acceleration. The earthquake design is based on allowable stresses as set forth in the applicable codes. The one-third increase in allowable stress normally associated with seismic loading was not used. The shear key provided in the drywell resists seismic and other lateral loads.

The torus was designed for horizontal and vertical accelerations as shown in table K.4-1, acting simultaneously at the mass center.

The vent ring header with eight vent lines has a computed fundamental frequency of 25.6 Hz. Response spectra developed for the reactor building were used to determine the seismic acceleration values. The analysis considered the flexibility of the drywell shell at the vent attachment and the vent line. Vent lines connecting the drywell to the vent header were assumed to provide horizontal restraint to the vent header. Vent header supporting columns were assumed to provide vertical restraint.

K.4.3 PRESSURES AND TEMPERATURES

During normal plant operation, the drywell is designed for temperatures up to 150°F at an internal pressure ≤ 2 psig. The torus chamber is designed for operating conditions up to 100°F and an internal pressure of ≤ 2 psig. During normal plant operation the torus contains ~ 90,000 ft^3 of water. The primary containment is also designed for an external pressure of 2 psig, at the various temperature levels.

The drywell, suppression chamber, and the vent system are designed for a maximum internal pressure of 62 psig, coincident with a temperature of 281°F under accident conditions.

Space is provided around the drywell vessel to allow thermal expansion in the operating or possible accident conditions so as to permit it to function as a pressure vessel.

K.4.4 JET FORCES

In the event of a postulated accident within the vessels, the containment is designed to withstand jet forces of the magnitudes described in table 12.3-3 acting in the indicated locations. The direction of load is arbitrary, coming from any direction within the drywell, and is assumed to be caused by a steam and/or water jet at 300°F.

Where the drywell is backed by concrete, the concrete shield which surrounds the vessel resists the jet force. Accordingly, the space between the drywell and the concrete shield is sufficiently small so that, although local yielding of the steel vessel can occur under concentrated forces, yielding to the extent causing rupture does not happen. Where the drywell is not backed up by concrete, the primary stresses resulting from the jet force loads do not exceed 0.9 times the yield point of the material at 300°F. However, when secondary stresses are combined with primary stresses, the allowable stress values are increased three times the normal allowable stress value as given in Table N-421 of Section III of the ASME Boiler and Pressure Vessel Code.

Jet protection barriers are provided for the eight vent openings inside the drywell to protect the vent system. Figure K.4-3 shows the location and details of a typical barrier utilized for the HNP-1 containment. The maximum permissible stress for such barriers is 0.9 x yield strength of the material for all loading combinations.

Jet protection barriers are also provided at each pipe penetration which includes a bellows to protect the bellows from pressure due to a jet directed toward the annulus between the guard pipe and the bellows, as shown in figure 5.2-1.

The suppression chamber and vent system are designed to withstand the vessel blowdown thrusts associated with the design basis loss-of-coolant accident. The design thrust on each 23 1/2-in.-diameter downcomer pipe is 21,000 lb.

Stresses resulting from these thrusts are limited to code allowable stresses.

K.4.5 GRAVITY LOADS

The gravity loads of the containment vessels and their appurtenances are considered in the design, as listed in table K.4-1.

K.4.6 OTHER LOADS

Among those loads considered in the design are the bellows loads from the reactor, refueling basin seal, and drywell to torus vent bellows. Also considered was the weight of contained air during tests, the reactions from each penetration, and the thermal gradient in the drywell shell in the embedment region.

TABLE K.4-1 (SHEET 1 OF 2)

DESIGN LOADS

Drywell and Vents

Design Pressures

Internal	Maximum	62	psig	@	281°F
	Design	56	psig	@	281°F
	Operating	< 2	psig	@	150°F
External	Maximum	2	psig	@	281°F
	Design	2	psig	@	281°F
	Operating	< 2	psig	@	150°F

Earthquake

Horizontal	See curves in figures K.4-1 and K.4-2.
Vertical	5.3% g for OBE and 10% g for DBE

Bellows Loads

Inside	Operating	60 lb/in.
	Refueling	67.5 lb/in.
Outside	Operating	30 lb/in.
	Refueling	125 lb/in.

Dead Weight Loads

Shell and appurtenances
Welding pads
Beam seat loads

Live Loads

Personnel lock floor
Monorail loads
Weld pads
Equipment and platform loads
Loads due to penetrations and bellows

Refueling Water

Weight of water supported at el 203 ft
5 in. during refueling operation

TABLE K.4-1 (SHEET 2 OF 2)

Flooded Containment (water up to el 227 ft)

Jet Force (See table 13.3-3.)

Weight of Contained Air (for test condition only)

Wind Loads (considered for drywell erection period only)

Steam Suppression Chamber

Design Pressures

Internal	Maximum	62	psig	@	281°F
	Design	56	psig	@	281°F
	Operating	< 2	psig	@	50° to 100°F
External	Maximum	2	psig	@	281°F
	Design	2	psig	@	281°F
	Operating	< 2	psig	@	50° to 100°F

Earthquake	OBE	OBE (drywell flooded)	DBE
Horizontal	12% g	20.5% g	20% g
Vertical	5.3% g	5.3% g	10% g

Dead Loads

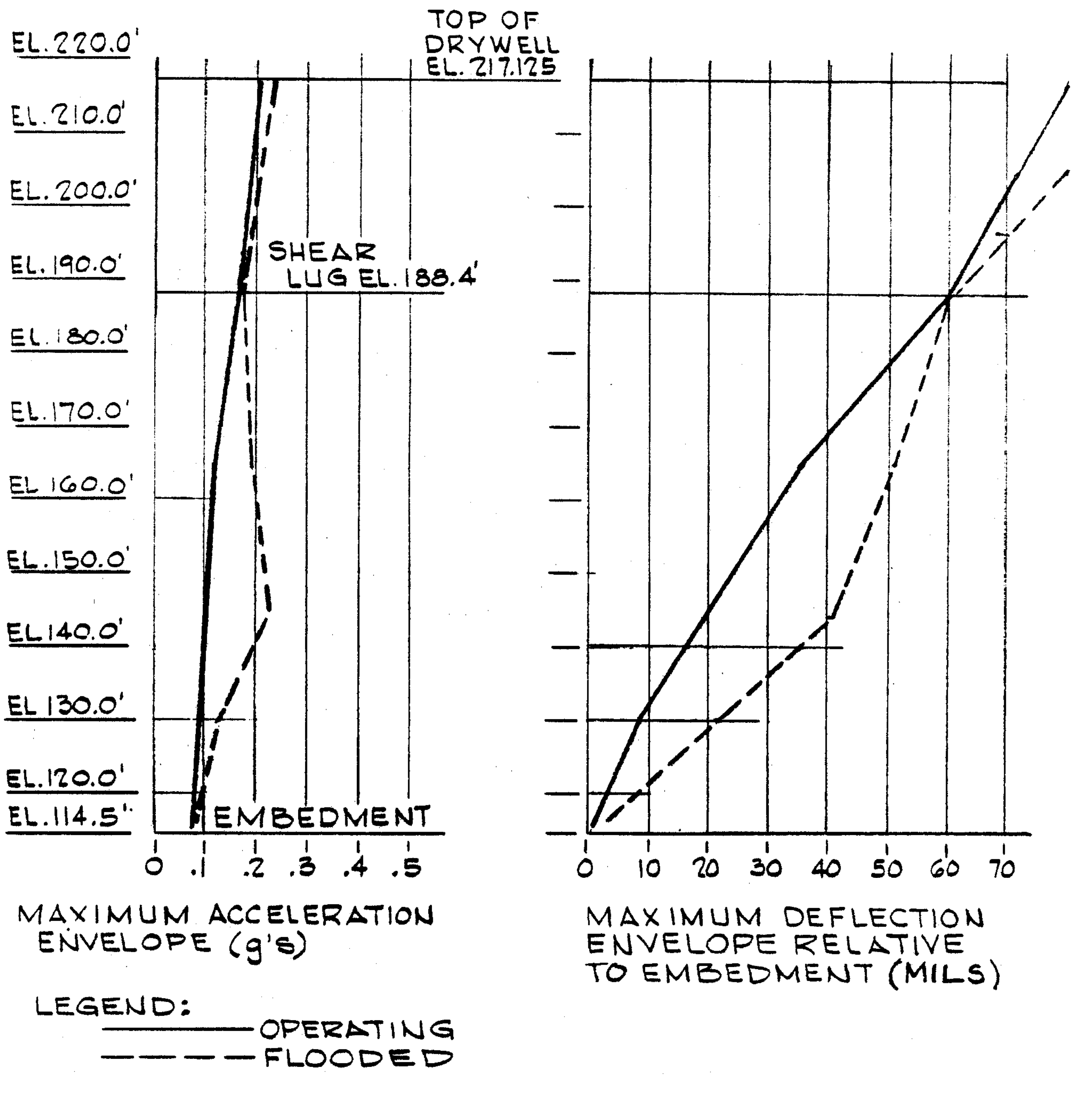
Shell and appurtenances
Welding pads

Live Loads

Monorail loads
Equipment and platform loads
Loads due to penetrations and vent bellows

Water Volumes

Flooded	211,089	ft^3 of water
Operating	90,000	ft^3 of water
Accident	97,000	ft^3 of water



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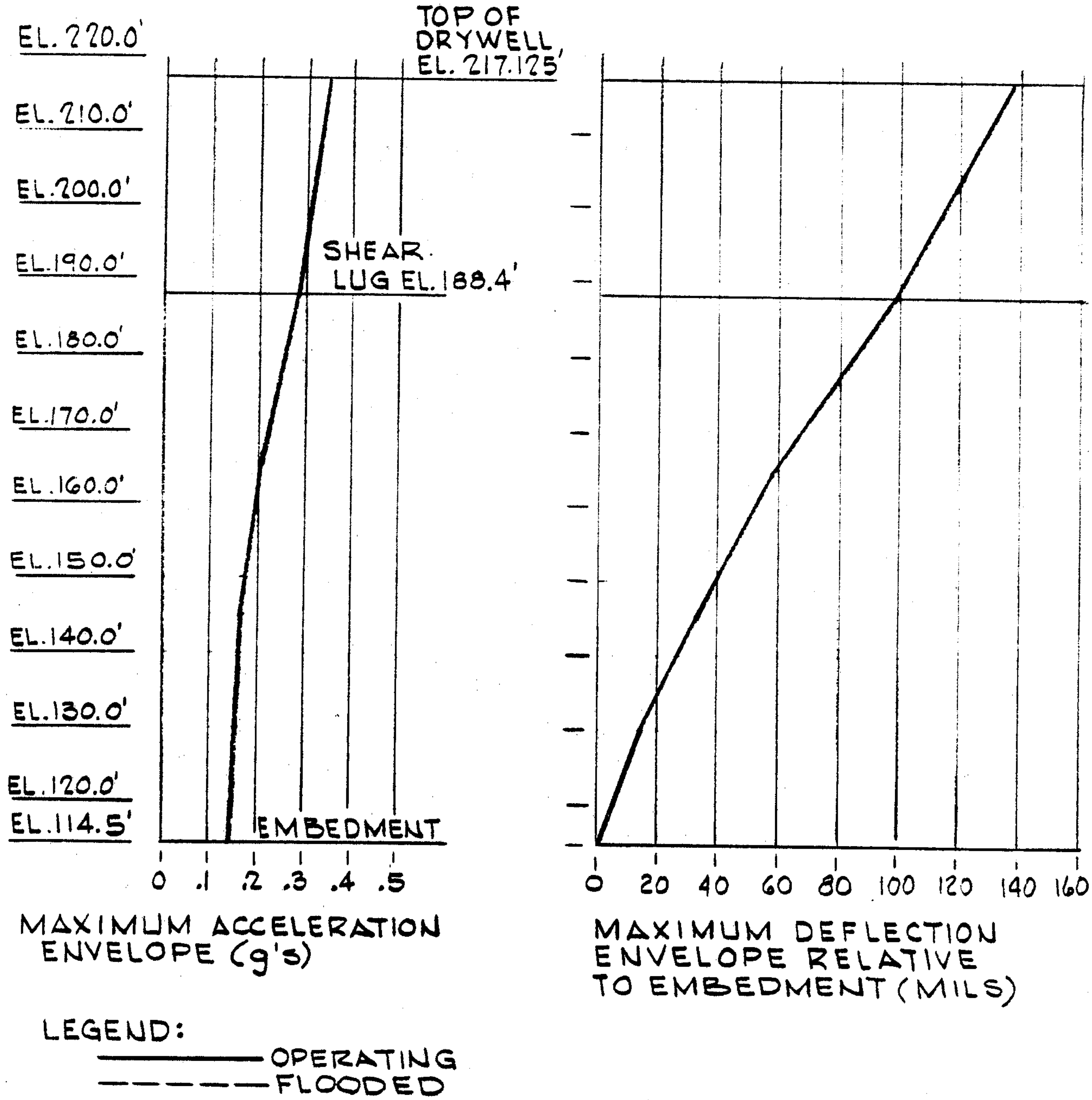
DRYWELL ACCELERATION AND DEFLECTION
(OBE)

FIGURE K.4-1



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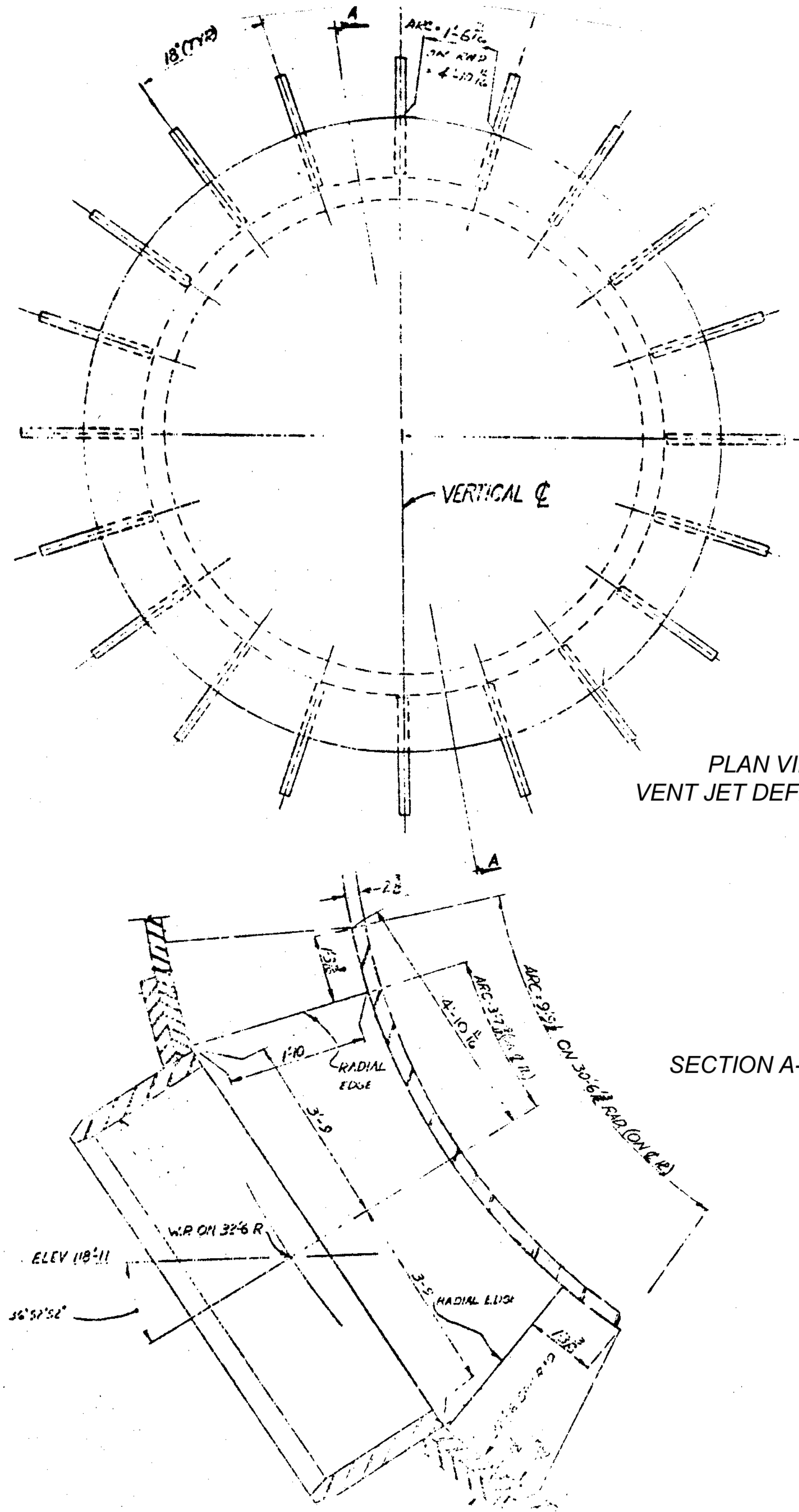
SOUTHERN COMPANY Energy to Serve Your World® SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 1	DRYWELL ACCELERATION AND DEFLECTION (DBE)
	FIGURE K.4-2



PLAN VIEW
VENT JET DEFLECTORS

SECTION A-A

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VENT JET DEFLECTORS

FIGURE K.4-3

K.5 LOADING COMBINATIONS

The drywell and vents were designed to withstand six combinations of loads. They are listed in table K.5-1. In cases 2 through 6, the drywell is considered laterally supported at el 188 ft 5 in. by the reactor building.

Case 1 is for the initial overload test conducted at 1.25 times the design pressure (1 1/4 x 56 = 70 psig).

Case 2 considers a leakage rate test to be performed at design pressure prior to plant startup. In addition to the stresses computed for the cylindrical and spherical portions of the drywell, stresses have been computed on the ellipsoidal head of the drywell. Under the design pressure, the circumferential and the meridional stresses are 7037 and 3513 psi, respectively, for the drywell head.

Case 3 considers the forces due to the operating condition and a slight positive or negative pressure on the vessel.

Case 4 considers the water load imposed on the drywell refueling bulkhead. A hydrostatic head is sustained from the bulkhead flange at el 203 ft to el 227 ft. Earthquake loading is also considered in the design.

Case 5 considers the accident conditions of increased temperatures, pressures, and jet loads.

Case 6 considers flooding of the drywell after an accident. Under this condition, the drywell is flooded with water to el 227 ft. Other loads, such as internal pressure, temperature, live loads, and jet forces are not combined with the hydrostatic load since these loads do not occur simultaneously with flooding. However, the drywell was analyzed for operating basis earthquake (OBE) loads combined with the hydrostatic loads.

The steam suppression chamber was designed to withstand five combinations of loads. They are listed in table K.5-2.

Case 1 is for the initial overload test conducted at 70 psig with 90,000 ft^3 of water stored in the torus.

Case 2 considers a leakage rate test to be performed in design pressure prior to plant startup. The 90,000 ft^3 of water is stored during this test.

Case 3 considers the forces due to the operating condition and a slight positive or negative pressure on the vessel.

Case 4 considers the accident conditions of increased temperature, pressures, water loads, and jet loads.

Case 5 considers the flooding of the vessel after an accident. Under this condition the torus is filled with water and hydrostatic pressure is considered for water up to el 227 ft. The torus was analyzed for OBE loads combined with the hydrostatic loads.

TABLE K.5-1

DRYWELL LOADING COMBINATIONS

Loads		Case No.:	Initial Test 1	Final Test 2	Normal Operating 3	Refueling 4	Accident 5	Flooded 6
Pressure (psig)	Internal		70	56	2		56	
	External			2	2	2		
Weld pads	Dead load		X	X	X	X	X	
	Live load			X	X	X		
Seismic	Horizontal	OBE	X	X	X	X	X	X
		DBE	X	X	X	X	X	
	Vertical	OBE	X	X	X	X	X	X
		DBE	X	X	X	X	X	
Dead load of vessel and appurtenances			X	X	X	X	X	X
Contained air			X					
Vent thrust			X	X	X		X	
Unrelieved deflection due to concrete load				X	X	X	X	X
Live load on personnel lock					X	X		
Live load on equipment access opening					X	X		
Refueling seal loads					X	X	X	
Jet forces							X	
Hydrostatic pressure due to flooding							X	

TABLE K.5-2

SUPPRESSION CHAMBER LOADING COMBINATIONS

Loads		Case No.:	Initial Test 1	Final Test 2	Normal Operating 3	Accident 4	Flooded 5
Pressure (psig)	Internal		70	56	2	56	
	External				2	2	
Weld pads	Dead load		X	X	X	X	
	Live load		X	X	X	X	
Seismic	Horizontal	OBE	X	X	X	X	X
		DBE	X	X	X	X	
	Vertical	OBE	X	X	X	X	X
		DBE	X	X	X	X	
Dead load of vessel and appurtenances			X	X	X	X	X
Suppression pool water			X	X	X	X	X
Combined air			X				
Vent thrust			X	X	X	X	
Live loads on catwalks and platforms				X	X		
Jet forces on downcomers						X	
Concrete loads				X			

K.6 ALLOWABLE STRESSES

The allowable stresses for different materials are listed in table K.6-1. These different material locations are identified in figure K.6-1.

The maximum computed primary stress value for the points shown in figure K.6-2 are listed in table K.6-2. It can be noted that for all loads in any stated combination the maximum computed primary stress is less than the code allowable stress value.

The design stress calculations considered compressive stresses and their effect on the overall stability of the containment vessels.

The following is a summary of criteria used for buckling:

- External pressure - American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code formulae.

- Uniaxial buckling stresses (nonstructural members) are limited to the "tubular column allowable" as explained in Welding Research Council Bulletin 69.

- Unequal biaxial buckling stresses (nonstructural members) are limited to a combination of tubular column allowable and equal biaxial allowable as explained in Welding Research Council Bulletin 69.

- Structural members per American Institute of Steel Construction (AISC) (Sixth Edition).

All the compressive stresses are within the code allowable values; hence, the margins against buckling failure are per the codes. The drywell is also designed for the flooded condition which is not governed by code allowable stresses. For this condition, the factor of safety against a buckling failure is 1.94.

TABLE K.6-1

MAXIMUM ALLOWABLE STRESSES

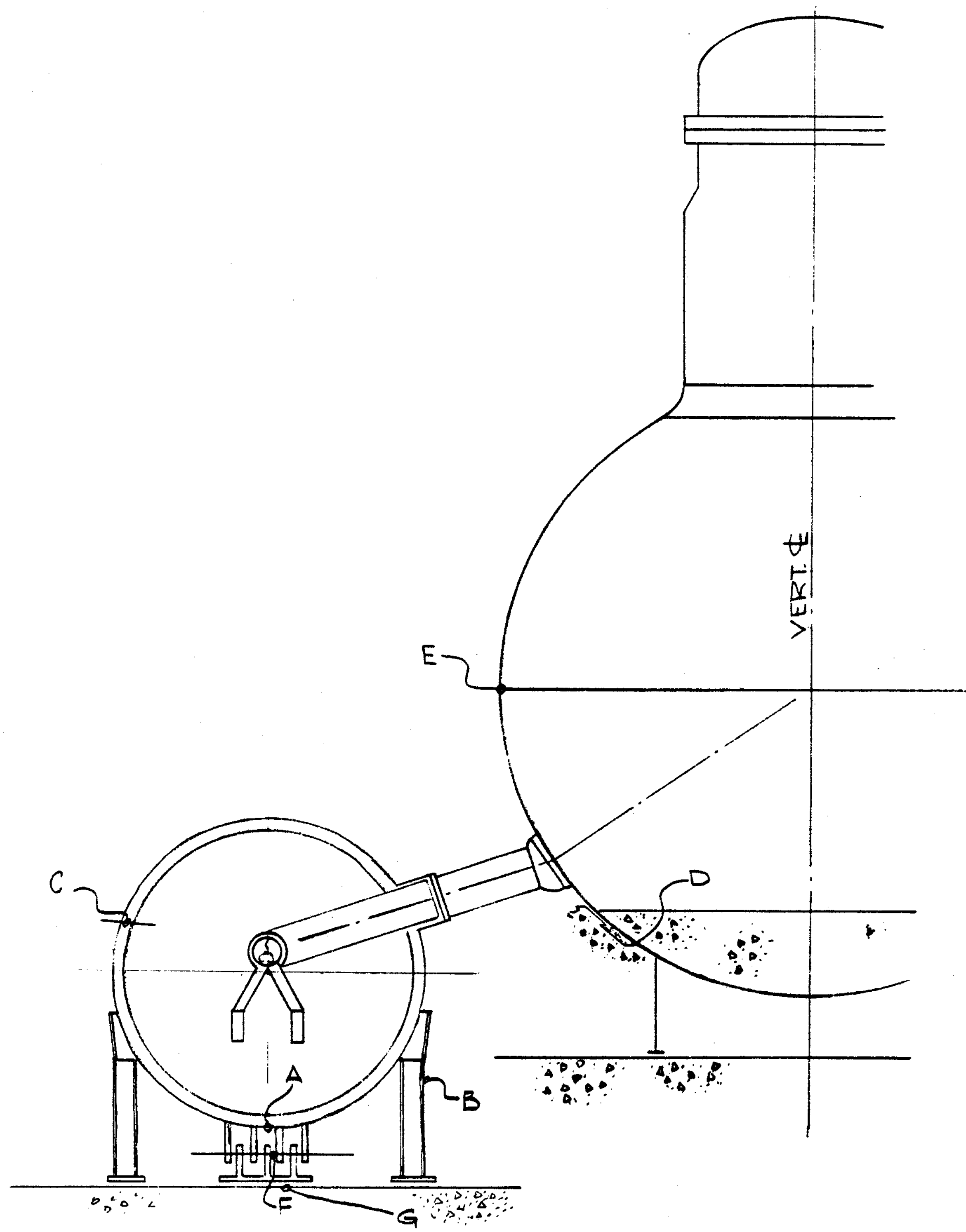
Point	Applicable Code	Type of Stress	Operating Condition OBE	Operating Condition DBE	Accident Condition OBE	Accident Condition DBE	Flooded Condition OBE
A	ASME III-B	Membrane	S_m	0.9 Sy	S_m	0.9 Sy	0.9 Sy
B	AISC	Bending	0.6 Fy	0.6 Fy	0.6 Fy	0.6 Fy	1.33 (0.6) Fy = 0.8 Fy
	(Plate)	Bearing	0.9 Fy	0.9Fy	0.9 Fy	0.9 Fy	Fy
		Shear	0.4 Fy	0.4 Fy	0.4 Fy	0.4 Fy	1.33 (0.4) Fy = 0.532 Fy
C	ASME III-B	Membrane	S_m	0.9 Sy	S_m	0.9 Sy	0.9 Sy
D	ASME	Membrane	S_m	0.9 Sy	S_m	0.9 Sy	0.9 Sy
E	ASME III-B	Membrane	S_m	0.9 Sy	S_m	0.9 Sy	0.9 Sy
F	AISC	Bearing	0.9 Fy	Fy	0.9 Fy	Fy	1.33 (0.9) Fy
	(Pin)	Shear	0.4 Fy	1.33 (0.4) Fy	0.4 Fy	1.33 (0.4) Fy	1.33 (0.4) Fy
G	ACI	Bearing	0.25 f′c	0.25 f′c	0.25 f′c	0.25 f′c	0.25 f′c
Welds							
	AISC Fillet and Groove	Shear	15,800 psi	21,067 psi	15,800 psi	21,067 psi	21,067 psi
	ASME Fillet	Shear	$\frac{0.55\ S_m}{0.707}$	$\frac{(0.55 \times 0.9\ Sy)}{0.707}$	$\frac{(0.55 \times 0.9\ Sy)}{0.707}$	$\frac{(0.55 \times 0.9\ S_m)}{0.707}$	$\frac{(0.55 \times 9\ Sy)}{0.707}$
	ASME Groove	Shear	0.6 S_m	0.6 (0.9 Sy)	0.6 (0.9 S_m)	0.6 (0.9 Sy)	0.6 (0.9 Sy)

TABLE K.6-2

MAXIMUM COMPUTED PRIMARY STRESSES[a]

Point	Maximum Meridional Stress (psi)	Case	Maximum Circumference Stress	Case
1	+2919	1	11,641	1
	-559	6	-1037	6
2	3733	1	21,624	1
	-674	6	-2825	6
3	5303	1	18,477	1
	-885	6	-2246	6
4	18,098	1	19,030	1
	-2811	6	-627	3
5	18,071	1	18,719	1
	-2239	6	-79	3
6	18,019	1	19,139	1
	-2808	6	-64	3
7	9827	1	10,531	1
	-1883	6	0	-
8	9783	1	10,948	1
	-2705	6	0	-
9	10,030	1	13,343	2
	-6241	6	-224	3
10	13,833	1	17,388	1
	0	-	0	-
11	14,025	1	18,121	1
	0	-	0	-

a. + stresses are tensile; - stresses are compressive.



(REFERENCE TABLE K.6-1 FOR LIST OF MATERIALS.)

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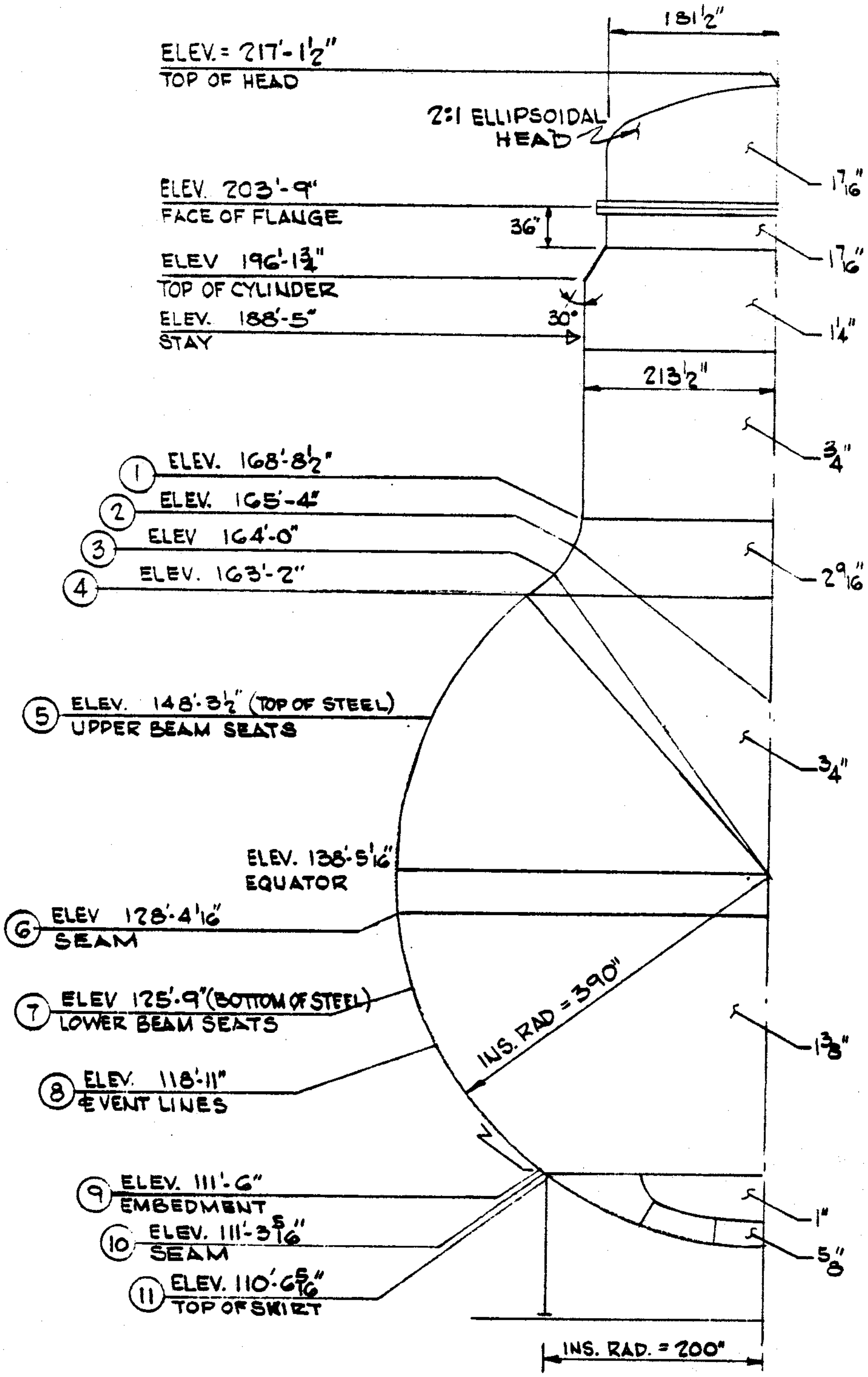
LOCATION OF DIFFERENT MATERIALS

FIGURE K.6-1



(REFERENCE TABLE K.6-2 FOR MAXIMUM COMPUTED PRIMARY STRESSES.)

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DRYWELL ELEVATION

FIGURE K.6-2

K.7 SPECIAL DESIGN CONSIDERATIONS

In addition to the general vessel design, a detailed analysis and design for the locations which carry local stresses and concentrated loads was performed. These locations are the beam seats, weld pad supports, sand pocket transition, drywell stabilizer, torus columns, shear ties, and penetrations. In addition, the design problem of jet force application is discussed herein.

The internal floors within the drywell and the equipment monorails are supported by the central reactor pedestal and the drywell shell plate (beam seats). The latter connections are slotted joints which transmit only the vertical loads to the drywell shell. A typical connection is shown in figure K.7-1.

Several 12-in.-diameter weld pads are located at various elevations in the vessels. These pads provide points of support for future internal loads. Due to their added strength, a weld connection at these points does not significantly affect the containment stress level around these areas.

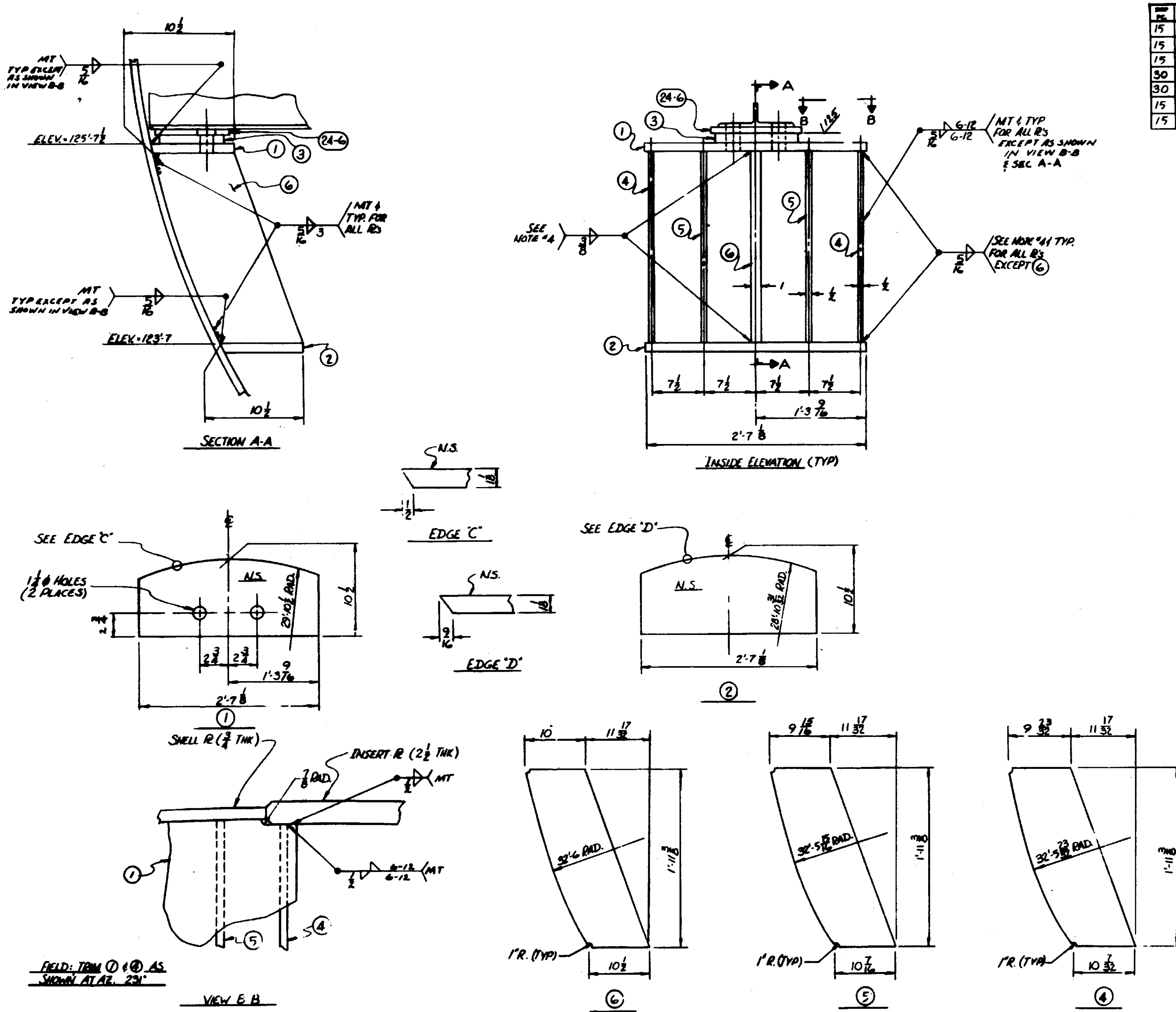
The sand pocket affords a structural transition from the fixity of the embedded drywell plate at el 111 ft 6 in. to the free pressure vessel plate at el 114 ft 6 in. Above this level, the vessel can deform radially through a 2 in. air gap without structural resistance. This zone was analyzed to check the maximum stress value, and stresses were found to be lower than the allowable stresses. At el 188 ft and 5 in., a system of horizontal stabilizers restrain the vessel from lateral movement relative to the reactor building. Lateral loads are transferred at these points to the external shield wall. The drywell shell acts in flexure as a beam of variable cross-section, fixed at the el 111 ft 6 in. and simply supported at the stabilizers. As shown in figures K.7-2 and K.7-3, the concrete building offers no radial or vertical restraints with this arrangement.

As shown on drawing no. S-15265, the entire vertical load of the torus passes through the ring girders to column connections. At these joints, concentrated stresses occur. Due to the complexity of the analysis involved in the determination of maximum stresses under various loads and load combinations, Chicago Bridge & Iron (CB&I) set up a computer program for each of the major loading combinations. These printouts are included in the Certified Stress Report. The maximum stress values at these locations were below the allowable stresses.

The torus columns are supported on sliding base plates which allow free movement of the torus. Lateral forces, generated by seismic motions, are restrained by shear ties. These pinned connections are located in pairs on two orthogonal major diameters and are welded to the invert of the torus.

At the intersection of the curved vessel surfaces and the penetrations, high local stress occurs. In addition to the interruption of uniform primary stress flow, the vessel experiences specified forces induced by the pipe penetrations. At these locations a thick reinforcing plate which conforms to the curvature of the shell replaces normal drywell plate and is welded to the drywell. The penetration pipe is welded to the reinforcing plate. The size of the reinforcing plate and the thickness of the pipe are prescribed by the code. Where penetrations are located in close proximity, a common reinforcing plate covering several penetrations is provided.

The containment vessel is subject to possible jet forces generated by the failure of pressurized internals. It is not feasible to design an elastic restraint for these accident loads, but it is possible to preclude the rupture of the containment envelope. Thus, to ensure that a steel shell could deflect 3 in. locally without rupture as a result of a concentrated load, CB&I conducted a series of tests on a steel plate formed to simulate a portion of the drywell vessel. The tests were satisfactory and also provided data on loading required to produce a given deflection, and the strain at various points of the shell.



SHIP PC.	MARK	ASSM. PC.	DESCRIPTION	LENGTH FT.	LENGTH IN.	SPEC.	
15	23-1		℞ SK x 1⅛ (C/15 ℞ 66 x 16'-0) SEE DWG. C13			*	B19/5
15	23-2		℞ SK x 1⅛ (C/W ①) SEE DWG. C13			*	B19/5
15	23-3		℞ 8½ x 1 W/HOLES	1	0½	* *	B20/5
30	23-4		℞ SK x ½ (C/30 ℞ 66 x 26'-0) SEE DWG C13			*	B19/7
30	23-5		℞ SK x ½ (C/W ④) SEE DWG. C13			*	B19/7
15	23-6		℞ SK x 1 (C/W (24-5)) SEE DWG. C13			*	B19/16
15	24-6		℞ 7½ x ½ (FM) W/HOLES (M/F ℞ 9½ x ½ x 1'-1)	1	1	A36	

* SA 516 GR70 TO SA300 (MS 504B)
** BRONZE LUBRITE ℞

GENERAL NOTES
1.) WORK THIS DWG. WITH DWG. #9.
2.) IN AREAS THAT ARE INACCESSIBLE TO MT EQUIPMENT, PT MAY BE SUBSTITUTED FOR MT.
3.) WELD ELECTRODE: SEE GENERAL PLAN FOR APPROVED TYPES.
4.) MT ONLY 4' OUT FROM SHELL.

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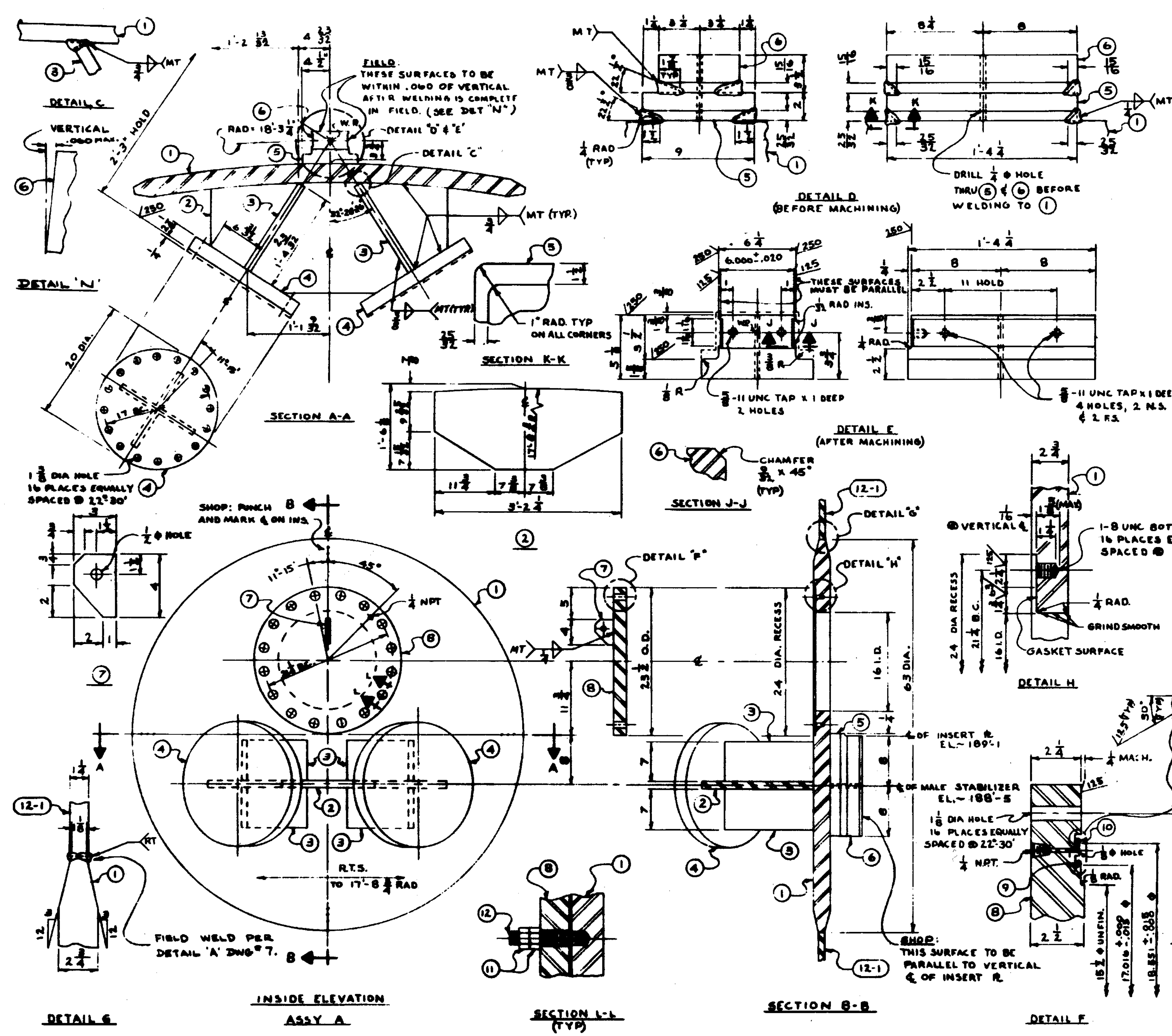
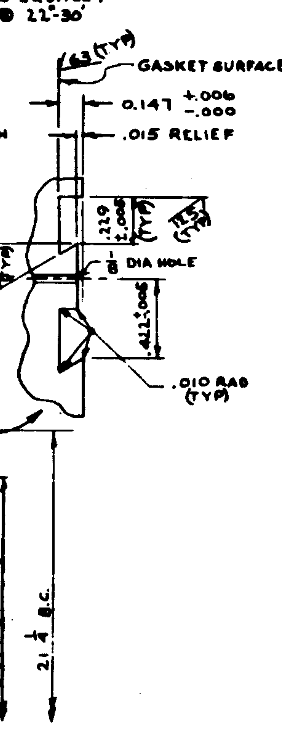
TYPICAL RADIAL BEAM SUPPORT

FIGURE K.7-1





SHIP PC.	MARK	ASM PC.	DESCRIPTION	LENGTH FT.	LENGTH IN.	SPEC.
8	27-A		MALE STABILIZER ASSY			
	27-1	8	℞ 63 ϕ X 2 ½ (C/F 64 X 21'-4 C4)			*
	27-2	8	℞ SK X 1 (C/F 64 X 17'-6 C8) SEE DWG C-10			*
	27-3	32	℞ 7 X 1 C/W (27-2)	1	4	*
	27-4	16	℞ 20 ϕ X 2 ½ (FIN)			*
			(C/F 98 X 2 ½ X 12'-2 C/10) SEE DWG C-10			
	27-5	8	℞ SK X 2 (C/F 96 X 16'-0 C/8) SEE DWG C-10	1	4 ½	*
	27-6	8	℞ SK X 3 ½ (FIN) (M/F 6 ½ X 3 ½ X 1'-4 ½)			*
			(℞ 58 X 3 ½ X 14'-0 C/8) SEE DWG C-10			
	27-7	8	℞ SK X ½ C/W (214-6) SEE DWG C-1			*
	27-8	8	℞ 23 ½ ϕ X 2 ½ FIN C/W (27-4)			*
	27-9	8	"O" RING 16.830 I.D. X .210 ϕ PARKER 5-081			* *
	27-10	8	"O" RING 18.350 I.D. X .210 ϕ PARKER 5-085			* *
	27-11	256	SEMI FIN. HEV. HEX NUT 1-8 UNC			SA194 GR.2
	27-12	128	STUD 1-8 UNC T.F.L.	0	5	SA193-B8
	27-13	8	½ ϕ 3,000# THD. SQ. HD. S.S. PLUG			SA182 F304

* SA516 GR 70 TO SA 300 (M5504)

* * SILICONE RUBBER - PARKER COMPOUND # S418-6 (60 DUROMETER)

NOTES

(1) IN AREAS THAT ARE INACCESSIBLE TO MT EQUIPMENT, PT MAY BE SUBSTITUTED FOR MT.
(2) P.W.H.T. ALL ASSEMBLIES IN SHOP AFTER WELDING IS COMPLETED AND PRIOR TO MACHINING.
(3) WELDING ELECTRODES - SEE GENERAL PLAN FOR APPROVED TYPES.

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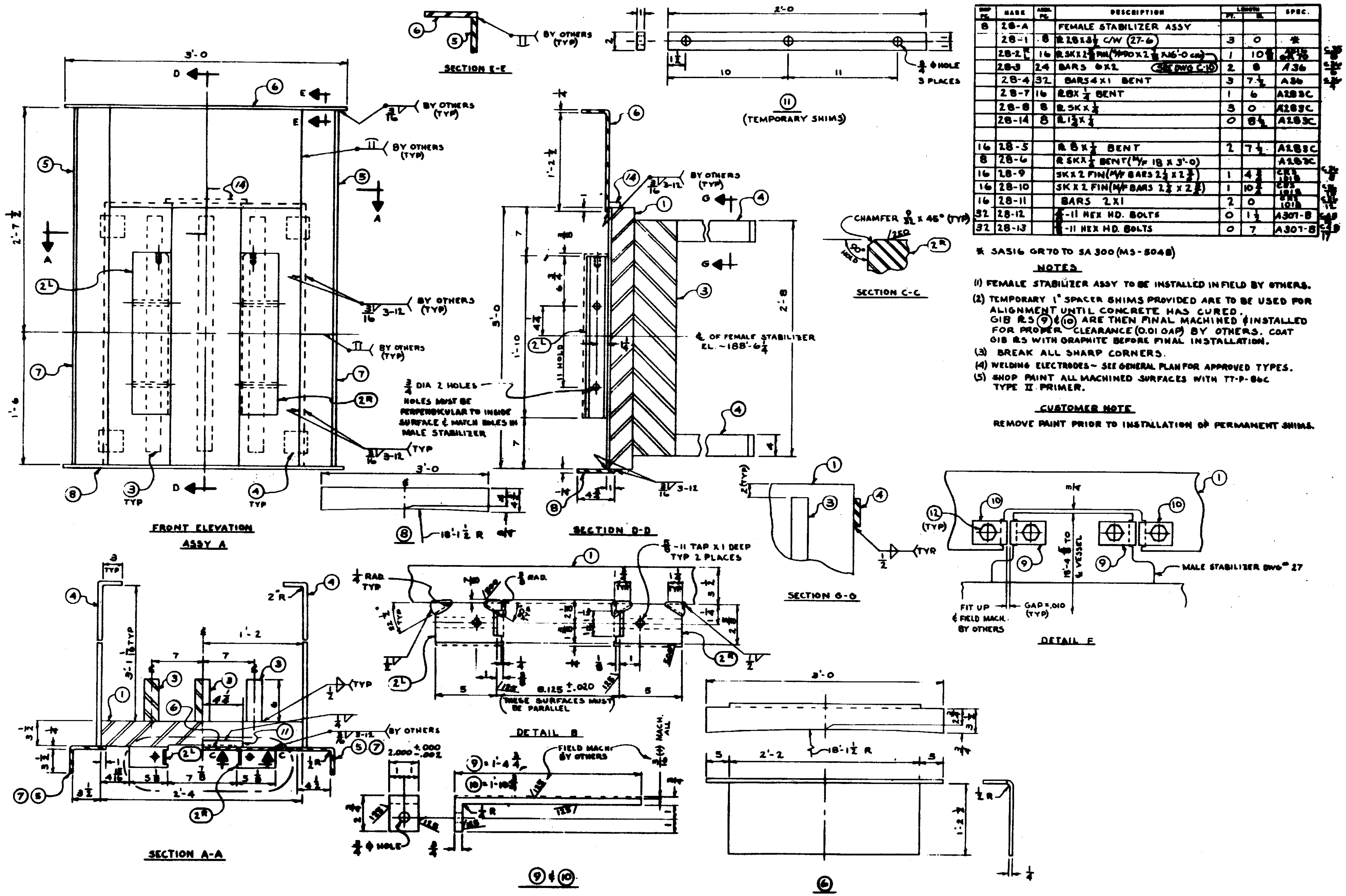
MALE STABILIZER ASSEMBLY

FIGURE K.7-2



SHIP PC.	MARK	ASSM. PC.	DESCRIPTION	LENGTH FT.	LENGTH IN.	SPEC.
8	28-A		FEMALE STABILIZER ASSY			
	28-1	8	R 28 x 3½ C/W (27-6)	3	0	*
	28-2	16	R 5K x 2½ FIN (M/F 90 x 2½ x 16'-0 cut)	1	10	
	28-3	24	BARS 6x2 (SEE DWG C-10)	2	8	A36
	28-4	32	BARS 4x1 BENT	3	7½	A36
	28-7	16	R 8X ½ BENT	1	6	A283C
	28-8	8	R 5K x ½	3	0	A283C
	28-14	8	R 1½ x ½	0	8½	A283C
16	28-5		R 8 x ½ BENT	2	7½	A283C
8	28-6		R 5K x ½ BENT (M/F 18 x 3'-0)			A283C
16	28-9		5K x 2 FIN (M/F BARS 2½ x 2½)	1	4	CRS 1018
16	28-10		SK x 2 FIN (M/F BARS 2½ x 2½)	1	10	CRS 1018
16	28-11		BARS 2x1	2	0	CRS 1018
32	28-12		-11 HEX HD. BOLTS	0	1½	A307-B
32	28-13		-11 HEX HD. BOLTS	0	7	A307-B

* SA516 GR70 TO SA 300 (MS-5048)

NOTES

(1) FEMALE STABILIZER ASSY TO BE INSTALLED IN FIELD BY OTHERS.
(2) TEMPORARY 1" SPACER SHIMS PROVIDED ARE TO BE USED FOR ALIGNMENT UNTIL CONCRETE HAS CURED. GIB RS 9 & 10 ARE THEN FINAL MACHINED & INSTALLED FOR PROPER CLEARANCE (0.01 GAP) BY OTHERS. COAT GIB RS WITH GRAPHITE BEFORE FINAL INSTALLATION.
(3) BREAK ALL SHARP CORNERS.
(4) WELDING ELECTRODES ~ SEE GENERAL PLAN FOR APPROVED TYPES.
(5) SHOP PAINT ALL MACHINED SURFACES WITH TT-P-86C TYPE II PRIMER.

CUSTOMER NOTE

REMOVE PAINT PRIOR TO INSTALLATION OF PERMANENT SHIMS.

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FEMALE STABILIZER ASSEMBLY

FIGURE K.7-3

K.8 INITIAL OVERLOAD AND LEAKAGE TEST

In addition to the production tests on all elements of the vessel, such as chemical, destructive, and nondestructive physical tests, the completed vessels were subjected to a battery of pressure tests to assure its containment integrity.

The primary tests consisted of an overload test and an integrated leak rate test. The overload test, as referenced in Section III and prescribed in Section VIII of the American Society for Mechanical Engineers Code, called for a 70-psig pressure load on the vessels. This test was performed on the vessel, including both doors of the personnel hatch. There was no visible structural distortion of the vessels.

The second test determined the leakage of the vessels for a 24-h period. After the overload test, the vessels were held at design pressure while hourly readings of temperature, humidity, and pressures were recorded. The loss of air was calculated. The primary containment leakage was below 0.2% for a 24-h period.

All removable covers have a double seal. The annuli between the seals were tested for leakage at the design pressure. The double-ply vent bellows were tested individually before and after the overload test for rupture and leakage.

The primary containment was again tested for leaktightness before startup of the plant when all the electrical assemblies and piping had been connected to the vessels.

This section is retained for *HISTORICAL* purposes to document a previous analysis that was done. The shield plug lifting requirement is that it be moved from above the reactor cavity with the Unit 1 single failure proof (SFP) overhead crane.

[HISTORICAL] [K.9 EVALUATION FOR IMPACT OF THE SHIELD PLUG

An analysis with the following assumed accident was performed to evaluate the impact of the shield plug. Analysis demonstrated that the facility has the ability to adequately respond to the accident. It also indicated that no failure of the nuclear process barrier would occur and there would be no hazard to the public.

A. *The plant has just shut down for refueling.*

B. *The overhead crane is in the process of removing the last of the six segmented drywell shield plugs.*

C. *The last segment has been raised to its highest possible elevation and the points of support of the lifting device sequentially fail in such a manner that one end of the segmented shield plug drops before the last remaining point of support of the lifting fails.*

D. *Due to the crane hook position and failure of the lifting device, the swing segmented plug orients itself so the dropped load is driven endwise between the reactor vessel and drywell biological shield directly over two of the main steam lines having the smaller ligament distance between them.*

   The analysis also included the following:

   - *The maximum reactor vessel pressure that exists when the removal of the segmented shield plugs commences.*
   - *The kinetic energy and velocity of the segment at the initial point of impact.*
   - *Identification of the point of impact and the amount of energy absorbed during impact.*
   - *The remaining kinetic energy in the segment and the gain in energy as it drops to the second point of impact.*
   - *Continuation of this analysis until the shielding plug segment comes to rest.*

Results and Conclusions

The maximum reactor pressure which is likely to exist at the time of removal of the segmented shield plugs is in the region of 800 psig.

The initial point of impact of the segment of the cap plug is on the edge of the drywell head with a velocity of 22.7 ft/s and kinetic energy of 992.0 ft-kips. By using the Stanford formula, the drywell head with 1 7/16-in. average thickness stops the falling segment and therefore prevents collision with the reactor vessel of piping inside the drywell or the control rod drive mechanisms. If view of the above analysis, which indicates that no failure of the nuclear process barrier would occur, there would be no hazard to the public.]

SUPPLEMENT KA

PLANT UNIQUE ANALYSIS OF THE MARK I CONTAINMENT SYSTEM

KA.1 INTRODUCTION

The Hatch Nuclear Plant-Unit 1 (HNP-1) containment system is one of the first-generation General Electric (GE) boiling water reactor (BWR) nuclear steam supply systems housed in a containment structure designated as the Mark I Containment System. The original design of the Mark I Containment System considered postulated accident loads previously associated with containment design, which included pressure and temperature loads associated with a loss-of-coolant accident (LOCA), seismic loads, dead loads, jet-impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads. However, since the establishment of the original design criteria, additional loading conditions have been identified that arise in the functioning of the pressure-suppression concept used in the Mark I Containment System. These additional loads result from the dynamic effects of drywell air and steam being rapidly forced into the suppression pool (torus) during a postulated LOCA and from suppression pool response to safety relief valve (SRV) operation generally associated with plant transient operating conditions. Because these hydrodynamic loads were not considered in the original design of the Mark I Containment System, the Nuclear Regulatory Commission (NRC) determined that a detailed reevaluation of the Mark I Containment System was required.

A two-phase program was identified to the NRC in May 1975. The first-phase effort, called the Short-Term Program (STP), provided a rapid assessment of the adequacy of the containment to maintain its integrity under the most probable course of the postulated LOCA. The first phase demonstrated the acceptability of continued operation during the performance of the second phase, called the Long-Term Program (LTP). In the LTP, detailed testing and analytical work was performed to define the specific design loads against which the containment was assessed to conform to established acceptance criteria.

The STP was completed in 1977, following the docketed submittal by Georgia Power Company (GPC) to the NRC of the HNP-1 plant unique analysis report (PUAR).[1] Reevaluation of the Mark I Containment System (STP and LTP) was completed in December 1983, following the docketed submittal by GPC to the NRC of the HNP-1 PUAR.[3]

KA.2 PLANT UNIQUE ANALYSIS REPORT

The Mark I Containment System reevaluation results are detailed in the PUAR submitted to the NRC in December 1983 and revised in December 1989 (reference 3). Many of the analyses presented in reference 3 assumed a 95°F initial suppression pool temperature. Subsequent analysis (reference 7) documents the acceptability of the reference 3 analyses at higher initial pool temperature (≤100°F). The PUAR demonstrates that the configuration of the plant, including structural modifications and load mitigation devices, meets the NRC requirements for the Mark I LTP as documented in the Mark I Containment Long-Term Program Safety Evaluation Report, NUREG-0661.[2]

The reference 7 analysis documents the containment loads analysis performed to justify operation at 2763 MWt. Reference 8 and reference 9 document evaluation of containment loads to support operation at 2804 MWt along with the reactor operating pressure increase to 1060 psia. Additional structural modifications were not required and NRC requirements for the Mark I LTP continue to be satisfied.

In summary, the PUAR report provides the following:

- A review of the event sequences involving the Mark I Containment System related phenomena for the postulated LOCA and SRV actuation conditions.
- A description of the major structural components of the HNP-1 containment system that were evaluated. The description includes both before and after status structural modifications.
- A review of the design criteria used, which includes both the design specification covering the fabrication and erection of the modifications and the structural acceptance criteria applying to the design analysis.
- A discussion of the system changes/additions made to the containment system to mitigate loads.
- A description of the loads and load combinations as applied in the HNP-1 analysis.
- A review of the computer programs used in the analysis.
- A summary of the analytical methods and models employed in evaluating each of the structural components.
- A summary of the analytical results for each structural component and a comparison with allowables, based on the structural acceptance criteria which demonstrate that the upgraded design-safety margins have been achieved.

KA.3 DESCRIPTION OF LTP MODIFICATIONS

The components significantly affected by the postulated LOCA and SRV actuation events are the suppression chamber, vent system, torus internal structures, SRV piping and supports, and the torus-attached piping and supports. Detailed analysis of the components determined that structural modifications and system changes were required to establish the NRC design-safety margins specified for the Mark I LTP. Table KA-1 presents a summary of the LTP modifications to the HNP-1 containment system. The modifications are in addition to the STP changes summarized in Appendix A of the PUAR.[3]

KA.4 EXPANDED OPERATING DOMAIN OPERATION

A containment loads analysis was performed to demonstrate that ample margins for containment integrity remained for plant operation in the expanded operating domain (EOD) at the maximum core inlet subcooling condition which was 100% power and 87% flow with reduced feedwater temperature. This analysis,[5] *which evaluated the containment pressure and temperature response and the containment hydrodynamic loads for a postulated design basis LOCA, was based on the methodology developed for the Mark I Long-Term Containment Program which is documented in the Mark I Containment Program Load Definition Report.*[6] *The results of this analysis showed that the peak containment pressure in the EOD with reduced feedwater temperature was 51.6 psig, which was higher than the value reported in NEDO-24570 of 47.9 psig, but below the design value of 56 psig and within the design margins shown in the PUAR. The containment hydrodynamic loads with EOD conditions were also within the design margins shown in the PUAR.*

The effect on containment loads including operation in the EOD was subsequently evaluated in reference 8 to support operation at 2804 MWt and in reference 9 for an increase in reactor operating pressure to 1060 psia. The evaluations indicate there is an increase in peak containment pressure, but the impact on containment loads is bounded by the results of the previous containment loads analysis. The evaluation for the pressure increase showed that the peak containment pressure in the EOD for a core power of 2804 MWt with reduced feedwater temperature is 50.0 psig, which is below the design value of 56 psig.

KA.5 OPERATION DURING PERIOD OF EXTENDED OPERATION

An analysis of the cumulative fatigue usage factor (CFUF) for the torus shell was performed to account for the period of extended operation. (See HNP-2-FSAR subsection 18.1.1 for a definition of the term "period of extended operation.") This analysis demonstrated the need to track actual thermal and dynamic loading events to ensure the torus shell maintains an actual CFUF ≤ 1.0 through the period of extended operation. The most limiting event for the torus is the steam blowdown resulting from the lifting of one or more main steam safety relief valves. The component cyclic or transient limit program (HNP-2-FSAR subsection 18.2.12) performs tracking of operational events. The CFUF analysis is a time-limited aging analysis and is described in HNP-2-FSAR section 18.5.

REFERENCES

1. "Torus Support System and Attached Piping Evaluation for E.I. Hatch Nuclear Plant Unit 1, Mark I Containment," NRC Docket No. 50-321, Bechtel Power Corporation, August 1976.

2. "Safety Evaluation Report Mark I Containment Long-Term Program," NUREG-0661, U. S. Nuclear Regulatory Commission, July 1980.

3. "Plant Unique Analysis Report for E.I. Hatch Nuclear Plant-Unit 1, Mark I Containment Long-Term Program," Revision 3, NRC Docket No. 50-321, Bechtel Power Corporation, December 1989.

4. (Deleted)

5. "Limiting Reload Licensing Events for E.I. Hatch Nuclear Plant Unit 1 and Unit 2," EAS 65-1088, General Electric Company, October 1988.

6. "Mark I Containment Program Load Definition Report," Revision 2, NEDO-2188, General Electric Company, November 1981.

7. "Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDC-32749P, General Electric Company, July 1997.

8. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

9. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE KA-1 (SHEET 1 OF 2)

LONG-TERM PROGRAM MODIFICATION SUMMARY

Component Category	Modification Description
Torus	Addition of saddle plate supports at 16 ring girder locations
	Addition of mid-bay column supports
	Addition of cone plates and ring girder/lip plate stiffening at 16 ring girder locations
	Addition of shell T-stiffeners
Vent system	Addition of vent header deflectors under vent header in non-vent bays
	Modification of existing downcomer ties
	Addition of stiffener plates to downcomer-vent header intersection
	Addition of stiffener plates to vent header intersection at vacuum breaker locations
	Addition of stiffener plates to vent lines at SRV line penetration locations
	Addition of pipe braces to existing vacuum breaker drain lines
	Addition of high-strength pins at ends of vent header support columns
	Cutting and capping of vent header drain lines
Internal structures	Modification of catwalk inside torus
	Modification of monorail inside torus
SRV piping	Addition of T-quencher discharge devices inside torus
	Addition of vacuum breakers to safety relief valve discharge lines (SRVDLs)

TABLE KA-1 (SHEET 2 OF 2)

Component Category	Modification Description
SRV piping supports	Addition of T-quencher supports Support beams Beam supports Gusset plate reinforcing
	Addition/modification of SRVDL supports inside drywell
Torus-attached piping and supports inside torus	Addition of elbows to RHR test lines
	Modifications to return line restraints
	Modifications to spray header supports
	Reroute instrument air lines; addition/modification of supports
Torus-attached piping and supports outside torus	Reroute small-bore piping
	Addition /modification of piping supports
Suppression pool temperature monitoring	Addition of thermowells and half-couplings
SRV logic change	Main steam isolation valve isolation level logic change
	SRV low-low set logic

APPENDIX M

REACTOR VESSEL OVERPRESSURE PROTECTION

See HNP-2-FSAR supplement 5A, Summary Technical Report of Reactor Vessel Overpressure Protection.

APPENDIX N

REPORT ON HIGH-ENERGY PIPE BREAKS OUTSIDE PRIMARY CONTAINMENT

N.1 PURPOSE

The purpose of this appendix is to summarize the capability of HNP-1 to withstand the effects of a high-energy line break outside the primary containment, to bring the reactor to a safe shutdown, and to maintain the reactor in a safe shutdown condition.

N.2 INTRODUCTION

This report is provided in response to the Atomic Energy Commission (AEC) request contained in their letter of December 15, 1972, to the applicant on the subject of high-energy piping system failures outside the primary containment. The analysis of the potential effects of a high-energy piping system failure and the ability to initiate and maintain a safe shutdown was performed in accordance with the criteria presented in the attachment to the AEC letter of December 15, 1972, entitled General Information Required for Consideration of the Effects of a Piping System Break Outside Containment as modified by the errata sheet sent under AEC cover letter to the applicant dated January 12, 1973. Portions of the attachment are repeated and all criteria are addressed specifically in this report.

A meeting was held between the applicant, its consultants, and the AEC on February 23, 1973 to review the status of Unit 1 with respect to the evaluation of high-energy piping system failures. A generally favorable impression of the design of Unit 1 was indicated by the AEC, and this report serves to support this favorable view.

As a result of Georgia Power Company's completed compliance with IEB 79-14, which required an evaluation of as-built safety-related piping systems, major portions of the piping referenced in this section were reanalyzed and/or rerouted. The potential effect of the work was to invalidate the analysis which is presented in this appendix. However, the piping systems which were modified or reanalyzed as a result of IEB 79-14 were reviewed to assure that any cracks or breaks (postulated) would not affect safety-related equipment or structures in such a manner that the reactor could not be brought to and maintained in a safe shutdown condition. The results of the evaluation are documented in the Final Safety Analysis Report.

N.3 GENERAL DESIGN EVALUATION

Prior to discussing the detailed evaluation of high-energy fluid system failures, some general comments are provided in subsections N.3.1 and N.3.2 with respect to the capability of Unit 1 to withstand the adverse effects of the postulated accident.

N.3.1 EVALUATION WITH RESPECT TO ATOMIC ENERGY COMMISSION (AEC) CRITERIA

Each of the 21 AEC criteria is addressed in tabular form below. Most of these criteria form the bases for the detailed system analyses discussed in section N.5. A general design evaluation, in conjunction with references to other portions of the Final Safety Analysis Report (FSAR), is provided to satisfy fully the intent of some of the criteria.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
1	N.4.1.1	(R) Systems for which pipe whip protection is required are identified.
2	N.4.1	(R) Systems for which jet impingement and environmental effects have been analyzed are identified.
	N.4.2.1, N.4.2.2	(R) Criteria for postulating failure locations are stated.
3	N.4.2.1	(R) Pipe break orientation criteria are stated.
4	N.5	(R) In lieu of performing dynamic analyses, it was assumed that, where a pipe break causes a pipe to move and strike an essential component, that component is lost unless the component is a pipe of equal or greater diameter and heavier wall thickness. (See footnote 1, AEC Criterion 1.) Target components are identified in section N.5.
5(a)	N.5.1.1	(R) Pipe anchors and restraints are designed for pipe rupture loads for main steam and feedwater lines.

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
5(b)	N.5	(R) Protective measures against direct effects are discussed by individual system.
5(c)	N/A	N/A
5(d)	N/A	N/A
5(e)	N/A	N/A
5(e)	N.5.1.1	(R) Criteria for design of anchors and restraints are stated.
6	N.5	(E) Seismic Class 1 reinforced concrete structures and members are evaluated by ultimate strength design methods of American Concrete Institute 318-63, Part IV-B, using the strain and stress assumptions of section 1503. Loads and load factors for this case are as follows: Maximum transient pressure — 1.1 Dead load — 1.0 Live load — 0 or 1.0 (to maximize effects) Earthquake, tornado, and normal thermal loads were not included. Seismic Class 1 structural steel members were evaluated by conventional working stress methods of the American Institute of Steel Construction Specifications using a one-third increase in allowable stresses, which provides sufficient margin against yielding.

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
7	N.4.4.1, N.5	(E) The structural design load resulting from pipe break consists primarily of differential pressures acting on the various walls and slabs. Peak values were computed in all areas, and the weakest member in each area was checked for adequate capacity. Concurrent loadings (such as dead, live, and equipment) were considered. Loads due to thermal stress were not considered since the high-temperature conditions were of short duration and, while some cracking of concrete or distortion of steel is possible, it is not likely that high temperature for short durations will result in failure or loss of function.
8	N.3.1, item 6	(E) Reversal of the normal stress pattern above was considered. Also, as indicated in item 6 above, the concurrent live load is conservatively assumed to be either 0 or 100% to maximize effects of possible stress reversals.
9	Chapter 12, N.6, N.5	(E) Vent openings added as modifications are discussed in sections N.5 and N.6 below. The net section in each of the modified slabs or walls is adequate to satisfy all criteria listed in chapter 12 of the FSAR.
10	N.5	(E) The failure of any structure or structural element is precluded, either by determining the acceptability of existing design or by modifying the existing design to withstand the effects of pipe breaks.
11	N.5, N.4.2.3	(R) The basic approach to maintaining required redundancy was to assume that the line being considered fails; any equipment damaged from the postulated line break's direct or environmental effects so as not to be functional, was considered part of the accident; after the accident, a single active failure was assumed to occur in the worst place with regard to shutdown capability; after these assumptions, the ability is maintained to shut down the reactor safely.

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
12	HNP-2-FSAR Chapter 15	(R) Habitability of the main control room (MCR) is addressed for main steam line break (MSLB).
	N.3.2	(E) The entire control complex, located in the control building, will not be adversely affected by any high-energy line failure.
	Paragraph 12.7.3.1	(R) MCR protection from design basis accidents is discussed.
13(a)	Table N.5-2, N.5	(R) Table of equipment required for safe shutdown is provided.
	HNP-2-FSAR Supplement 15C	(R) Time after postulated accident and duration required for the operation of shutdown equipment is documented.
13(b)	Chapter 7	(R) Qualification tests for cabling and other related electrical equipment are described.
	Chapter 7	(R) Radiation tolerances for cabling and other electrical equipment are documented.
	Chapter 7	(R) Qualification tests for valve operators are described.
	N.5	(R) Environmental conditions are summarized.
13(c)	N.4.3, N.5	(R) Barriers provided to protect electrical equipment from pipe whip and jet forces are discussed in section N.5.
13(d)	Criterion 12 above	(R) No adverse environment in the control complex is expected.
13(e)	N.3.2, N.5	(R) Onsite emergency ac power sources are located in a separate protective structure (diesel generator building).
14	N/A	N/A

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
15	N.5	(R) Any adverse effects of steam or water flooding are addressed by individual line break.
	Chapter 6	(R) Design against flooding of safety-related equipment in the reactor building is discussed.
	Chapter 11	(R) Flooding effects and design features for the turbine building are discussed.
16	Appendix A, Appendix D	(E) Further quality control or inspection is not required.
17	N.5.3	(E) One additional leak detection system has been installed. The addition of a temperature sensor at the el 130-ft floor of the reactor building near the pipe penetration room on the east side of the drywell enables detection of a failure in the high-pressure coolant injection (HPCI) steam line at < 300% flow which isolates the HPCI steam line isolation valve.
18	HNP-2-FSAR Supplement 15C	(R) Shutdown procedure to be followed without loss of offsite ac power is described.
	HNP-2-FSAR Supplement 15C	(R) Shutdown procedure to be followed with loss of offsite ac power is described.
	Table N.5-2	(R) Table of equipment required for safe shutdown is provided.
	N.5	(R) Shutdown procedure, including effects of single-active failure, to be followed for each individual break is provided.
19	Appendix A	(E) Description of seismic and quality classification of safety-related high-energy lines is provided.
	N.3.2	(E) Item 9 provides seismic classification for main steam lines.

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

AEC Criterion No.[a]	FSAR References[b]	Remarks (R) or General Design Evaluation (E)
20	N.4.4	(R) Summary of approach, assumptions, and computer model is documented.
	Table N.5-1	(R) Blowdown energy and time interval for each line break is tabulated.
	N.5	(R) Results of each analysis is given by individual system.
21	N.5	(E) The structural capabilities of the primary and secondary containment structures were evaluated for direct effects of the postulated breaks and the effects of external and differential pressure. Special vendor qualification was obtained to assure adequate margin in the results as applicable to the primary containment.

N.3.2 INHERENT PLANT SAFETY FEATURES WITH RESPECT TO DESIGN AGAINST HIGH-ENERGY PIPE FAILURES

The following is a list of inherent safety features of HNP-1 which enable the plant to withstand the effects of high-energy piping system failures. These safety features are stated generally, and references are provided which discuss the design features in more detail.

1. All safeguard equipment is located within Seismic Class 1 structures with redundant features being physically separated by distance as well as Seismic Class 1 walls. See also chapter 12.

2. The control complex, including the battery rooms, cable spreading room, switchgear rooms, and MCR, is located in a separate Seismic Class 1 structure. As shown in figure N.5-2, 5-ft-thick Seismic Class 1 concrete walls separate the control complex from the compartment containing the main steam and feedwater lines. See also chapter 12 and HNP-2-FSAR chapter 15.

3. The diesel generators and their associated equipment and emergency power sources are located in a separate Seismic Class 1 structure physically removed from the turbine and reactor buildings. No postulated high-energy pipe failure can cause pipe whip, jet impingement, or environmental damage to the onsite emergency ac power supply.

a. Refers to the AEC criteria attached to the December 15, 1972, letter to the applicant.
b. Including applicable portions of this appendix.

4. There is no equipment or instrumentation located in the turbine building proper which would obviate the ability to shut down the reactor safely if damaged from a high-energy line failure. The cable chase area below el 147 ft 0 in. of the turbine building is designed to Seismic Class 1 criteria. There is a 5-ft-thick Seismic Class 1 barrier between the main steam and feedwater piping located above el 147 ft 0 in., and the cable chase area below. This structural element precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building on the cables. The postulated failure of a high-energy pipe occurring in the turbine building will not prevent safe shutdown of the reactor.

5. The environmental qualification of cable is described in the Edwin I. Hatch Nuclear Plant (HNP) Central File for the Qualification of Safety-Related Equipment. The criteria for cable routing are provided in section 8.8.

6. The performance of the valve operators used within and outside the primary containment under high-temperature saturated steam conditions is documented in the HNP Central File for the Qualification of Safety-Related Equipment.

7. There are no safeguard instrument panels located in close proximity to high-energy piping nor are there direct line-of-sight paths of communication between high-energy pipes and safeguard panels. Therefore, there are no direct effects of pipe whip and jet impingement on such panels due to the postulated high-energy pipe failures.

8. The ventilation supply to the control room is on the west side of the control building at el 180 ft 0 in., i.e., the side away from the reactor building. As such, the possibility of steam from a postulated high-energy pipe break being drawn into the control room is remote. As indicated in HNP-2-FSAR chapter 15, the MCR is automatically isolated by the main steam line high-flow signal indicative of an MSLB. Also, radiation monitors are provided in the control room intake to provide automatic isolation of the MCR upon receipt of a high-radiation signal.

   None of the postulated high-energy line failures can cause pipe whip, jet impingement, external overpressurization, or environmental damage to the control complex or radiation hazard to the operators.

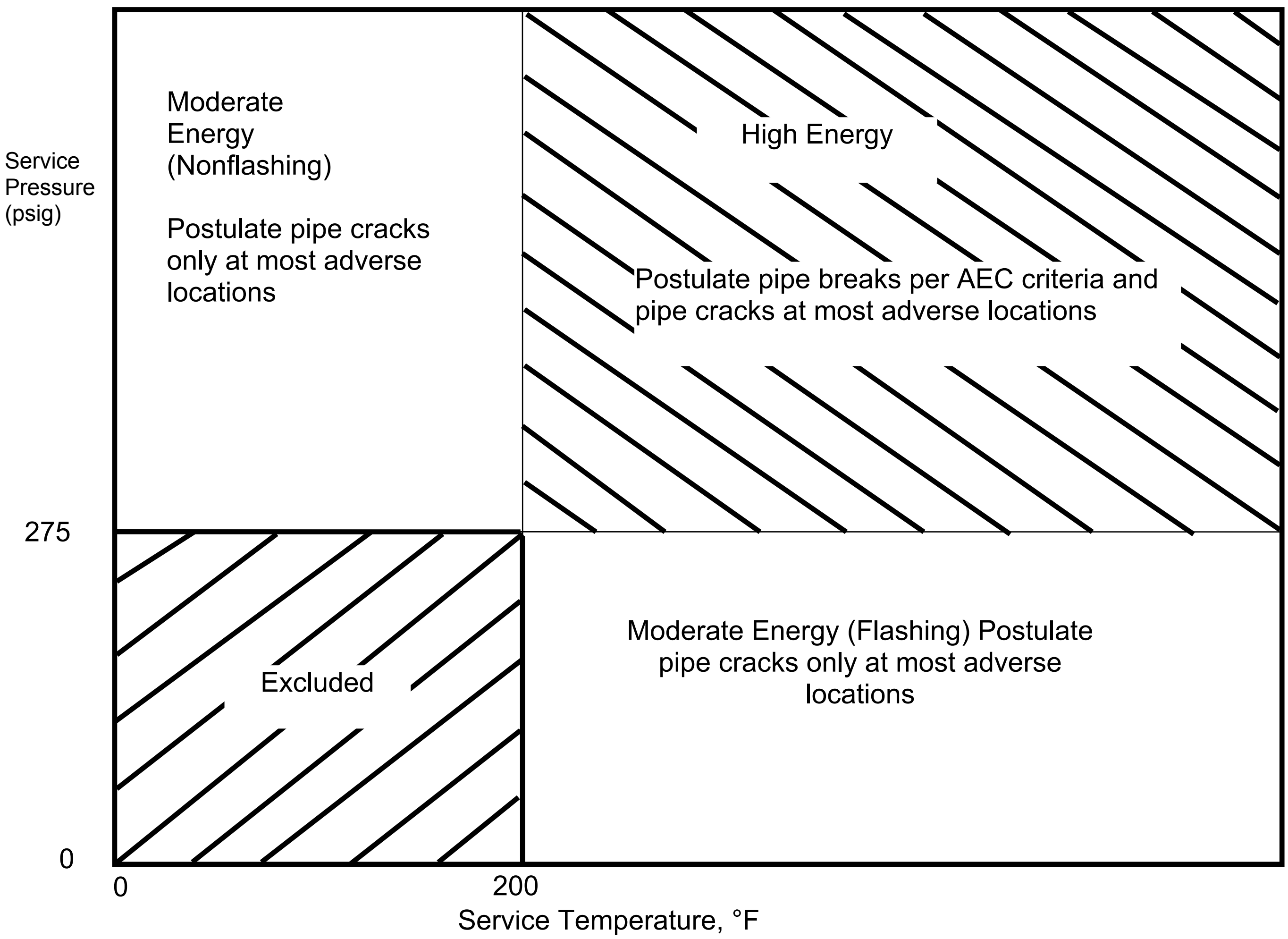
9. In addition to the quality classification provided in appendix A, the main steam lines were analyzed to Seismic Class 1 criteria out to the turbine stop valves in the turbine building.

10. Relief vents in the roof of the reactor (600 ft^2) and turbine (3000 ft^2) buildings were designed to relieve at 55 lb/ft^2 (~0.4 psid) for a tornado. These vents will, however, perform the function of venting from internal pressure without damage to the structure.

N.4 METHODS OF ANALYSIS AND ASSUMPTIONS

N.4.1 IDENTIFICATION OF HIGH-ENERGY FLUID SYSTEMS

The criteria for identification of high-energy fluid systems outside the primary containment are schematically summarized below. The high-energy and moderate-energy lines identified per the Atomic Energy Commission (AEC) criteria are listed below as applicable to the schematic diagram.



High-energy lines identified in paragraph N.4.1.1 are evaluated for direct effects of pipe whip and jet impingement and for all adverse environmental effects (pressure, temperature, radiation, and flooding). Moderate-energy lines identified below are evaluated for the direct effects of jet impingement and for adverse environmental effects.

N.4.1.1 High-Energy Lines Identified

For postulating pipe breaks per AEC criteria and pipe cracks at the most adverse locations, high-energy lines have been identified. (See table N.4-1.)

N.4.1.2 Moderate-Energy Lines Identified

For postulating critical size cracks, moderate-energy lines have been identified. (See table N.4-2.)

N.4.2 HIGH-ENERGY PIPING SYSTEM FAILURE ASSUMPTIONS

N.4.2.1 High-Energy Line Breaks

In accordance with AEC Criterion 2, piping systems identified in paragraph N.4.1.1 are assumed to break as follows:

A. Circumferential breaks are perpendicular to the pipe axis, and the break area is equivalent to the internal cross-sectional area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially and cause movement in any direction normal to the pipe axis. Circumferential breaks are to be considered in pipes exceeding 1-in. nominal pipe size.

B. Longitudinal breaks are parallel to the pipe axis, and the break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis. Longitudinal breaks are to be considered in pipes of 4-in. nominal pipe size and larger.

C. Where it was considered significant to the evaluation of the consequences of a break to determine whether or not a break is circumferential or longitudinal, the stresses at that location were investigated to determine whether axial stress or hoop stress predominates. Where the total axial stress predominates, a circumferential break is postulated. Where hoop stress predominates, a longitudinal break is postulated.

In accordance with AEC Criterion 2, circumferential and/or longitudinal breaks have been assumed to occur at the following locations in each piping run or branch run:

- Terminal ends.

- Any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operation plant conditions exceed 0.8 $(1.2\ S_h + S_A)$[a] or the expansion stresses exceed 0.8 S. If there are no locations where these stresses are exceeded, then a minimum of two intermediate breaks will be postulated and selected on the basis of highest stress.

N.4.2.2 High-Energy and Moderate-Energy Line Cracks

In accordance with AEC Criterion 2 (as modified by the errata sheet referenced in Section N.2 above), high-energy and moderate-energy lines identified in paragraphs N.4.1.1 and N.4.1.2 above, are assumed to develop critical size cracks, which are taken to be one-half the pipe diameter in length and one-half the wall thickness in width. These cracks are assumed to occur at any location along the length and at any point around the circumference of the pipe.

N.4.2.3 Other Failure Assumptions

In addition to the assumptions for postulating breaks or cracks, other failure assumptions include:

1. The postulated break or crack was assumed to occur during normal operating conditions at rated power.

2. No other accident was assumed to occur concurrently with the pipe failure outside the containment.

3. A single failure of an active component has been assumed to occur in the analysis of the accident and the ability to safely shut down the reactor.

4. A loss-of-offsite ac power was assumed to occur only for line breaks which would result in an immediate reactor trip. The possibility of reactor trip for each line break is discussed in paragraph N.5.3.2.

N.4.3 JET IMPINGEMENT AND PIPE WHIP ANALYSIS

A thorough examination of each high-energy line identified in paragraph N.4.1.1 above, to determine the direct effects of pipe whip and jet impingement, was made both by detailed drawing analysis and actual site evaluation. Certain safety-related cables and electrical components were identified to require protection from jet impingement on the basis of maintaining redundancy, and it was conservatively decided to provide protective barriers for the

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a. S_h is the stress calculated by the rules of NC-3600 and ND-3600 for Class 2 and 3 components, respectively, of the ASME Code, Section III, Winter 1972 Addenda. S_A is the allowable stress range for expansion stress calculated by the rules of NC-3600 of the American Society of Mechanical Engineers (ASME) Code, Section III, or the USA Standard Code for Pressure Piping, American National Standard Institute (ANSI) B31.1.0-1967.

pipes. Where provided, barriers are designed in accordance with the analytical methods described in BN-TOP-2.[a][3] The locations where such protective means are provided are identified in the detailed system analyses in section N.5.

The drywell pneumatic system and the nitrogen system are not specifically protected from the effects of a pipe break which occurs outside the drywell, except at the drywell penetrations. Credit is taken for local operator action to restore within 2 h this pneumatic supply if damaged by a pipe break occurring outside the drywell. This is a time critical operator action as defined in Unit 2 FSAR subsection 15.1.5.

N.4.4 COMPARTMENT PRESSURE TEMPERATURE ANALYSIS

N.4.4.1 General Approach and Assumptions

In accordance with AEC Criterion 20, a complete pressure temperature transient analysis was performed for each compartment containing a postulated failure of a high-energy or moderate-energy line. Details of these analyses are discussed by individual system in section N.5; however, the general approach and assumptions applicable to all such analyses are as follows:

A. The pressure temperature transient analysis was performed for the compartment in which the high-energy and/or moderate-energy (flashing) line failure was postulated (compartment 1) as well as for the other affected compartments which have direct or indirect communication with the original compartment.

B. The blowdown and energy releases from the broken lines are given in table N.5-1. To obtain maximum break area, a pipe is considered to be instantaneously and completely severed. Two-phase mixture carryover time has been calculated by General Electric, using the LAMB code. A mixture quality of 7% was assumed for the mixture portion of the blowdown. Moody frictionless blowdown was assumed for major process lines, and the flow was considered critical at the point of minimum flow area.

   The blowdown code referenced is the portion of the General Electric Company computer program used to numerically evaluate the blowdown and core flow terms of the generic Short-Term Thermal-Hydraulic Model. A detailed description of this model is presented in Appendix A to General Electric Topical Report NEDO-10329, dated April 1971. The specific portions of the model covering flow out of pipe breaks and separation regions are described in NEDO-10329, Appendix A, paragraphs A.2.3.3 and A.2.4.4, respectively.

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a. BN-TOP-2 is also referenced in the Grand Gulf Preliminary Safety Analysis Report, Docket No. 50-416.

C. The blowdown was assumed to last for the time interval corresponding to the maximum allowable closing times of the isolation valves as quoted in the Technical Requirements Manual, plus an additional signal delay time. The blowdown interval for each line break is provided in table N.5-1.

D. The short-term temperature pressure transient analysis was calculated using a modified version of the Bechtel code COPRA. The code and analysis are described in paragraph N.4.4.2. The temperature and pressure in different compartments, as well as the differential pressures across specific walls, are listed by system in section N.5. The short-term pressure transient analysis does not include any heat transfer. Long-term temperature transients in the compartment were obtained from the Bechtel code COPATTA. Credit was taken for walls and slabs as heat sinks in the long-term analyses. All other potential heat sinks were neglected.

E. The capability of the compartments and structures to withstand the resultant pressures was evaluated. In addition, the performance capability of components necessary for safe shutdown was evaluated to determine the effect of the resultant environment. Pipe breaks affecting component performance capability may be in the same room with the component of concern or in adjacent rooms. See table 7.16-7 for equipment qualification parameters.

F. In cases where the pressure or temperature or both exceeded acceptable values on structures, structural elements, or the design requirements of critical equipment, an analysis was performed to determine the vent area required to reduce the pressures and temperatures to acceptable values. This additional vent area was then incorporated in the design, and the final analysis was performed to verify the acceptability of the design change. In evaluating the capability of structures or structural elements to withstand the resultant pressures, a value of 90% of ultimate stress was used. Since the calculation of the ultimate strength of structural elements was performed conservatively, the actual margin with respect to ultimate is greater than the 10% allowed in the pressure calculations. Detailed results of these calculations are provided by system in section N.5.

N.4.4.2 The Computer Model

A modified version of the Bechtel computer program, COPRA, was used for the short-term pressure transient analysis. The program solves the continuity equation, the energy and momentum conservation equations, and the equations of state. The program can accommodate a maximum of 100 control volumes and 5 flow paths from each control volume. The program is set up to select the control volume and flow path configuration that results in the best representation of the pressure transients in the compartments along the flow paths from the first compartment to the downstream compartments.

The blowdown data are added in time increments to compartment 1 in which the line break is postulated. The program then solves the conservation equation and equations of state to determine the thermodynamic state in compartment 1. The momentum equation is then solved for each flow path to obtain the flow during each time step from compartment 1 to each connected compartment. The conservation equation and equations of state are again solved to determine the thermodynamic state in the compartment for the beginning of the next time increment. This procedure is repeated in sequence for each compartment except that the flow from the upstream compartments replaces the blowdown. The pressure in each compartment is calculated using the total mass and energy in that compartment after the flow from the upstream compartments (or the blowdown) has been added to the inventory of mass and energy in that compartment.

There are two options for the choice of flow equations. Depending on the line break, the Moody equation or the compressible fluid flow equations can be used. The flow coefficients for the different types of vents are treated in the same way as the orifice and nozzle flow coefficient calculations used in the Bechtel COPRA code.

N.4.4.2.1 COPATTA Analytical Methods and Conservatisms

Computer Program Description

The long-term temperature transient analysis were performed using the COPATTA computer program. The COPATTA code is Bechtel's program to analyze the effects of a loss-of-coolant accident on the containment building. COPATTA was derived from the original CONTEMPT code.(1) The present COPATTA program is written in Fortran IV and uses the GE635 Computer.

To determine the long-term temperature response, the COPATTA analysis was begun after the compartment peak pressures had been attained. The initial conditions used were taken from the results of the compartment analysis at the time corresponding to the start up time for COPATTA. The code then calculated the heat transferred from the atmosphere to the structures, thus determining the compartment temperature as a function of time.

COPATTA Model

The COPATTA code as used in this case is based on thermodynamic equilibrium modeling of a two-region compartment. The two-region compartment model predicts pressure and temperature histories of the compartment atmosphere and temperature histories of the compartment sump, the compartment structure, and various heat sinks within the structure.

The two regions which are incorporated in the COPATTA model are the compartment atmosphere and the compartment sump. The compartment atmosphere is a vapor region, and the compartment sump is a liquid region. The code calculates pressure-temperature transients for each of the regions by use of a finite difference, stepwise iteration between thermodynamic states. Iterations are based on the conservation of energy, mass, and their related functions.

Energy is transferred between the liquid and vapor regions by boiling with evaporation neglected. A convective heat transfer coefficient of zero is used as a conservative representation of the convective heat transfer. Each of the regions is assumed homogeneous with temperature differences allowable between the regions. Any moisture condensed in the vapor region during each step is immediately added to the sump (liquid) region. All noncondensible gases are included in the vapor region of the model.

Thermodynamic Assumptions

The basic COPATTA program calculates conditions in two separate regions of the compartment: a water region in the sump and an atmosphere region. In a thermodynamic sense, the two regions are open systems since the program permits mass flow across the boundaries of each of the regions. The expression of the first law of thermodynamics for such open systems is:

$$\frac{\partial U}{\partial t} = \sum_j \frac{dQ}{dt} + \sum_i h \frac{dm_i}{dt}$$

where:

U = the internal energy of the system (Btu).

Q = heat energy addition to the system (Btu).

h = enthalpy of the mass entering the system (Btu/lbm).

m = mass entering the system (lbm).

t = time (h).

Integration of the above equation for each region, from the start of the transient to any later time, provides the thermodynamic properties with which the static point conditions of pressure and temperature can be determined. Numerical integration of the thermodynamic equations for each of the regions and the calculation of properties within the regions are based on the following assumptions:

A. At the break point, the discharge flow separates into a steam phase which is added to the compartment atmosphere (vapor) region and a water phase which is added to the compartment sump (liquid) region. The water phase is at the saturation temperature corresponding to the total compartment pressure, while the steam phase is at the partial pressure of the steam in the compartment.

B. The compartment atmosphere pressure is also the sump pressure.

C. The steam-air mixture and the water phase are each assumed homogenously mixed with uniform properties. Specifically, thermal equilibrium between the air and steam is assumed. A temperature difference may exist between the atmosphere region and the liquid region.

D. All of the steam condensed from the atmosphere during any time interval is added to the sump immediately at the end of the interval.

E. Mass and energy are transferred from the liquid region (sump) to the compartment atmosphere by boiling if the calculation indicates that the compartment pressure is less than the saturation pressure corresponding to the liquid temperature.

F. The sump region contains no water at the beginning of the transient.

G. Condensation of steam due to a vapor pressure gradient between the steam in the compartment atmosphere and the water in the sump is neglected.

H. Condensation of the steam on structural heat sinks occurs at the saturation temperature corresponding to the total pressure in the compartment. Thus, during atmospheric superheat conditions, the condensing boundary layer is at saturation conditions.

Atmosphere and Sump Regions

Initially, the compartment system is entirely composed of water vapor and air occupying the free volume of the compartment. The water vapor and air partial pressure, masses, and internal energies are determined from the initial temperature, total pressure, and relative humidity. During the first advancement, a step input of mass and energy can be added to the compartment atmosphere.

The transient pressure and temperature calculations are made by considering the mass, volume, and energy equations for the water, steam, and air in the compartment atmosphere and sump regions. These equations give:

$$M = m_w + m_s + m_a$$

$$V = m_w v_w + m_s v_s + m_a v_a$$

$$U = m_w u_v + m_s u_s + m_a u_a$$

where:

M = total mass of water (w), steam (s), and air (a) (lbm).

m = individual constituent mass (lbm).

V = total system free volume (ft^3).

v = individual constituent specific volume (ft^3/lbm).

U = total internal energy of water, steam, and air (Btu).

u = individual constituent specific internal energy (Btu/lbm).

The above equations are solved iteratively for each time advancement until a specified convergence criterion is satisfied. The respective water (w), and steam (s) properties used in the equations are evaluated based on the steam table values for water or steam at their respective temperatures T_w and T_s. Air (a) properties are evaluated at the air temperature, T_a. By assumption, the steam temperature and the air temperature are equal to the vapor region temperature, T_v. The specific volume of air, v_a, is calculated from the Ideal Gas Law; the air specific internal energy, u_a, is calculated from:

$$u_a = C_v(T_v - T_0)$$

where:

C_v = 0.171 Btu/lbm -°F, the specific heat of air.

T_0 = the initial containment atmosphere temperature (°F).

Once the mass, volume, and energy equations are solved for the converged values of T_w and T_v, the compartment pressure is calculated.

The total compartment pressure is computed from the sum of the partial pressures of steam and air at the compartment atmosphere temperature, T_v. The steam partial pressure is taken from the steam table values, and the air partial pressure is computed from the Ideal Gas Law relationship.

Heat Transfer Considerations

Heat transfer takes place between the compartment atmosphere, and the exposed surfaces inside the compartment. The only heat sinks used in this analysis were the concrete walls and slabs (totaling 31,960 ft^2). All miscellaneous equipment and structural steel within the compartment was conservatively neglected. The rate of heat transfer between the compartment regions and these conducting masses is determined by the surface area, the surface temperature, the heat transfer coefficient, the physical arrangement of the conducting masses, and the thermal properties of these masses. All of the above parameters are considered by the COPATTA computer program during the transient analyses as described in this section.

Heat Conduction Calculations

The COPATTA program makes provision for the simulation of up to 20 heat conducting masses in the analytical model. These heat conducting masses are described by a one-dimensional, multiregion heat conduction equation given by:

$$\rho C \frac{dT}{dt} = \nabla(K \nabla T) + S$$

where:

T = temperature (°F).

t = time (h).

K = thermal conductivity (Btu/h-ft-°F).

ρC = volumetric heat capacity (Btu/ft^3-°F).

S = volumetric heat generation rate (Btu/h-ft^3).

The spatial gradient operator, ∇, is applied in any of three coordinate systems in order to perform heat transfer calculations for rectangular, cylindrical, or spherical geometries.

The input for the heat conduction calculation includes provisions for specifying the geometry, the surface area, the number, and coordinates for different material regions, the mesh point spacing, and the material type for each heat-conducting mass. The mesh point spacing used in this analysis was 0.1 in. for the first 6 in. and 0.5 in. for the remainder.

Boundary conditions ranging from perfectly insulated (adiabatic) to zero resistance are applied to each of the heat conducting mass external surfaces, as appropriate. These boundary conditions may indicate exposure to a constant temperature, a time dependent temperature, the compartment atmosphere or sump temperature, or some combination of the above. Heat transfer coefficient control is similar, ranging from values of zero through values dependent on the steam/air ratio in the compartment atmosphere or the condensing steam value which is dependent upon a turbulence parameter inside the compartment.

During the post-blowdown period of the transient which is the period of interest in this case, a steady-state condition develops due to decreasing turbulence in the compartment. Heat transfer under these conditions is dependent upon the steam-air steady-state mixture. Experimental work by Uchida, et al., shows that during free convection cooling periods, the condensing heat transfer coefficient is dependent on the ratio of noncondensable gas to steam masses.[(2)] Application of the Uchida data during the long-term cooling period (based on the reduction of turbulence in the compartment), specifies the condensing heat transfer coefficient during the transient.

The heat transfer coefficient between the water regions of the sump and the heat sinks is assumed to be 0.0 Btu/h-ft^2-°F. Zero heat transfer is specified at the liquid-vapor interface between the compartment sump and atmosphere regions. These conservative values assure maximum temperature conditions within the compartment.

N.4.4.2.2 Modified COPRA - Compartment Pressure Temperature Analyses

The section describes the analytical techniques used to evaluate high-energy pipe rupture.

The masses of air and water as steam in the compartments are determined using the initial input conditions of temperature, pressure, relative humidity, and compartment volume. The specific humidity of saturated air at the compartment temperature is read from a correlation table of temperature and water vapor in saturated air. The compartment specific humidity is obtained by:

$$SH = (RH)(SSH) \tag{1}$$

where:

SH = specific humidity of compartment air, lb steam/lb air.

RH = relative humidity of compartment air.

SSH = specific humidity of saturated air at compartment temperature, lb steam/lb air.

The vapor pressure of the water is determined by:

$$PW = \frac{(SH)(PT)}{0.623 + SH} \tag{2}$$

where:

PW = vapor pressure of water at compartment temperature (psia).

PT = total compartment pressure (psia).

The air pressure in the compartment is determined by:

$$PW = PT - PW \tag{3}$$

The mass of air in the compartment is evaluated using the Ideal Gas Law equation:

$$MA = \frac{(144)(PA)(V)}{\left(R/n\right)(T)} \tag{4}$$

where:

V = volume of compartment (ft^3).

R = gas constant, 1545.3.

T = compartment temperature (°R).

n = molecular weight of air, 28.97 lb/lb mole.

The mass of water in the compartment, MS, is:

$$MS = (MA)(SH) \tag{5}$$

The masses of air and water in the remaining compartments are determined in the same manner.

The energy of the air in each compartment is calculated using 0°F as a base:

$$UA(I) = [CV][MA(I)][TP] \tag{6}$$

where:

CV = specific heat of air at constant volume, 0.171 Btu/lb-°F.

TP = compartment temperature (°F).

The energy of the water vapor in each compartment is calculated by the equation:

$$US(I) = [MS(I)][UG] \tag{7}$$

where:

UG = internal energy of the steam evaluated from the saturated steam tables at the compartment temperature.

The inventory of the total mass and energy in the compartments is maintained from the inlet and exit flows during the time increment:

$$MA(I) = MA'(I) + \sum^{N} |MAI| - \sum^{N} |MAO| \tag{8}$$

$$MW(I) = MW'(I) + \sum^{N} |MWI| - \sum^{N} |MWO| \tag{9}$$

$$MS(I) = MS'(I) + \sum^{N} |MSI| - \sum^{N} |MSO| \tag{10}$$

$$MV(I) = MW(I) + MS(I) \quad (11)$$

$$MT = MV(I) + MA(I) \quad (12)$$

$$UA(I) = UA(I) + \sum^{N} |UAI| - \sum^{N} |UAO| \quad (13)$$

$$UW(I) = UW(I) + \sum^{N} (HI|MWI|) - \sum^{N} (HO|MWO|) \quad (14)$$

$$US(I) = US(I) + \sum^{N} (HGI|MSI|) - \sum^{N} (HGO|MSO|) \quad (15)$$

$$UV(I) = UW(I) + US(I) \quad (16)$$

$$UT(I) = UV(I) + UA(I) \quad (17)$$

where:

Primed $(')$ values refer to end of previous time step, all other values refer to current time step.

MW(I) = mass of water in compartment (I)(lb).

MV(I) = mass of water and steam in compartment (I)(lb).

MT(I) = total mass in compartment (I)(lb).

MAI = mass of air entering compartment (lb).

MAO = mass of air leaving compartment (lb).

MWI = mass of water entering compartment (lb).

MWO = mass of water leaving compartment (lb).

MSI = mass of steam entering compartment (lb).

MSO = mass of steam leaving compartment (lb).

UAI = total energy of air entering compartment (Btu).

UAO = total energy of air leaving compartment (Btu).

HI = enthalpy of water entering compartment (I)(Btu/lb).

HO = enthalpy of water leaving compartment (I) (Btu/lb).

HGI = enthalpy of steam entering compartment (I)(Btu/lb).

HGO = enthalpy of steam leaving compartment (I)(Btu/lb).

UA(I) = energy in air in compartment (I)(Btu).

UW(I) = energy in water in compartment (I)(Btu).

US(I) = energy in steam in compartment (I)(Btu).

UV(I) = energy in vapor in compartment (I)(Btu).

UT(I) = total energy in compartment (I)(Btu).

<u>Compartment Pressure Calculations</u>

The compartment pressure is calculated using the total mass and energy in the compartment after the flow from the upstream compartments and/or the blowdown has been added to the compartment inventory of mass and energy. A convergency procedure is used to arrive at the equilibrium thermodynamics conditions in the compartment using temperature as the trial argument. The equilibrium thermodynamic state is considered determined when the trial temperature provides properties such that the ratio of the difference between the trial energy balance and the energy inventory is less than 0.001. The state properties of the steam and water mixture at the trial temperature are obtained from the saturation tables. The mass of steam is then determined by:

$$MS = \frac{\left[(V) - (MW)_1 (VL)\right]}{VG} \tag{18}$$

where:

$(MW)_1$ = mass of water, previous iteration (lb).

V = volume of compartment (ft^3).

VL = specific volume of water (ft^3/lb).

VG = specific volume of steam (ft^3/lb).

The mass of water (MW) is determined by:

$$MW = MV - MS \tag{19}$$

A trial energy balance is calculated:

$$\text{ETRIAL} = (\text{MS})(\text{UG}) + (\text{MW})(\text{UL}) + 0.171(\text{MA})(\text{TP}) \quad (20)$$

The procedure is repeated varying the value of TP until the relation:

$$\frac{(\text{UT} - \text{ETRIAL})}{\text{UT}} \leq 0.001 \quad (21)$$

is satisfied.

If, after establishing the thermodynamic equilibrium conditions, MW ≤ 0, the compartment is considered to be superheated. The equilibrium conditions are recalculated by setting the steam mass equal to the vapor mass and calculating the steam pressure at the search temperature by:

$$\text{PS} = \frac{0.5961(\text{MS})(\text{T})}{\text{V}} \quad (22)$$

PS = pressure of steam (psia).

T = compartment search temperature (°R).

V = compartment volume (ft^3).

0.5961 = R /(Mole Weight)(144).

= 1545.3 / (18)(144).

The internal energy of the steam at the pressure and temperature is obtained from the superheat tables and a trial energy balance calculated by:

$$\text{ETRIAL} = (\text{MS})(\text{UG}) + 0.171(\text{MA})(\text{TP}) \quad (23)$$

The procedure is repeated varying the value of TP until the relation:

$$\frac{(\text{UT} - \text{ETRIAL})}{\text{UT}} \leq 0.001 \quad (24)$$

is satisfied.

The total pressure in the compartment is the sum of the steam pressure and the air pressure with the latter being calculated by:

$$\text{PA} = \frac{0.37\text{MA}(\text{TP} + 459.688)}{\text{V}} \quad (25)$$

where:

$$0.37 = \frac{R}{(\text{Mole Weight})(144)} = \frac{1545.3}{(28.97)(144)}$$

Flow Calculation

A compressible fluid flow equation is used for the analysis of compartment pressure.

In the application of the compressible fluid flow equation, if the ratio of the pressure in the downsteam compartment (compartment 2) to the pressure in the upsteam compartment (compartment 1) is less than RC as obtained by:

$$R = \left[\frac{2}{1+K}\right]^{\frac{K}{K-1}} \tag{26}$$

the flow is considered to be critical. The form of the flow equation is:

$$G = \left[2g_c(K)(P1)(RHO1)\left[\frac{2}{K+1}\right]^{\frac{K+1}{K-1}}\right]^{\frac{1}{2}} \tag{27}$$

The isentropic exponent K for the air, steam, and water mixture leaving the compartment is calculated by:

$$K = KGF\frac{PS(I)}{PT(I)} + \frac{PA(I)}{PT(I)} \tag{28}$$

where:

KA = isentropic value of K for air of 1.4.

KGF = isentropic value of K for steam-water mixture.

RHO1 = MT(I) / VOL(I) (lb/ft^3).

P1 = Compartment 1 pressure (psia).

g_c = gravity acceleration, 32.174 ft/s^2.

If the flow is subcritical, the form of the flow equation is:

$$G = \left[\frac{2(g_c)(P1)(RHO1)K\left(R^{\frac{2}{K}} - R^{\frac{K+1}{K}}\right)}{K-1} \right]^{\frac{1}{2}} \quad (29)$$

where the terms are as previously defined and R = P2/P1 and P2 = compartment 2 pressure.

The mass flow from compartment 1 to compartment 2 is calculated by:

total	MF	=	GAC (lb).	(30)
air	MAF	=	[MF][MA(I)] / MT(I) (lb).	(31)
water	MWF	=	[MF][MW(I)] / MT(I) (lb).	(32)
steam	MSF	=	[MF][MS(I) / MT(I) (lb).	(33)

The energy transferred by the flow is:

air	UAF	=	[(MAF)(CP)]TC(I)] (Btu).	(34)
water	UWF	=	(MWF)(HL) (Btu).	(35)
steam	USF	=	(MSF)(HG) (Btu).	(36)

where:

A = area of flow path (ft^2).

G = mass flow (lb/ft^2-s).

C = coefficient calculated external to code.

CP = specific heat of air at constant pressure.

HL = enthalpy of water at compartment temperature.

HG = enthalpy of steam at compartment temperature.

The flow coefficient C was calculated using the same methods as outlined in the COPRA Computer Program which has been previously submitted for AEC review in NS-731-TN, Containment Pressure Analysis, Power and Industrial Division, Bechtel Corporation, San Francisco, California, December 1968.

REFERENCES

1. Richardson, L. C., et al., "CONTEMPT - A Computer Program for Predicting the Containment Pressure - Temperature Response to a Loss-of-Coolant-Accident," 17220, Phillips Petroleum Company, June 1967.

2. Uchida, H., et al., "Evaluation of Post-Incident Cooling Systems of Light-Water Power Reactors," Third International Conference on the Peaceful Uses of Atomic Energy, p 93, New York, 1965.

3. "Design for Pipe Break Effects," BN-TOP-2, Bechtel Corporation, San Francisco, California, Revision 0, September 25, 1972.

TABLE N.4-1

HIGH-ENERGY LINES

High-Energy Line	Service Temperature (°F)	Service Pressure (psig)	Pipe Diameter (in.)	Pipe Schedule
Main steam	551.7	1045	24	80
Feedwater	392.4	1095	18	120
High-pressure coolant injection steam	551.7	1045	10	80
Reactor core isolation cooling steam	551.7	1045	4	80
Reactor water cleanup (RWC)	531.4	1211/1050	4/6[a]	80
Residual heat removal (RHR) discharge[b]	280[c]/117[d]	340[c]/190[d]	24	30

a. These values apply to piping upstream of the RWC pump.
b. Breaks and cracks are not postulated to occur in these lines due to infrequent and short-term periods (< 1.5 h during cooldown) during which the AEC temperature and/or pressure criteria are exceeded.
c. At the onset of RHR shutdown cooling operation.
d. At the end of RHR shutdown cooling operation.

TABLE N.4-2

MODERATE-ENERGY LINES

Moderate-Energy Line	Service Temperature (°F)	Service Pressure (psig)	Pipe Diameter (in.)	Pipe Schedule or Thickness (in.)
Nonflashing				
Control rod drive return	100	1029	3	80
RHR service water	95	415	18	0.500
Flashing				
Auxiliary steam	450	175	10	40
Auxiliary steam supply to nitrogen inerting system	450	175	2	80
RHR suction[a]	328[b]/125[c]	170[b]/20[c]	20	30

a. Cracks are not postulated to occur in this line due to infrequent and short-term periods (1.5 h during cooldown), during which the AEC temperature criterion is exceeded.
b. At the onset of RHR shutdown cooling operation.
c. At the end of RHR shutdown cooling operation.

N.5 DETAILED SYSTEM ANALYSES

The following considerations were applied to the detailed system analysis in addition to those discussed by individual high-energy line failure:

1. Safe shutdown includes meeting those criteria discussed in HNP-2-FSAR supplement 15C. Criteria discussed in HNP-2-FSAR supplement 15C include not exceeding: radioactive release values of 10 CFR 100, mechanical and thermal limits for catastrophic failure of the fuel barrier, nuclear and containment system stresses allowed for accidents by applicable codes, radiation exposure limits for control room personnel specified in General Design Criterion 19 of 10 CFR 50, Appendix A.

2. Normal shutdown procedure (as described in HNP-2-FSAR supplement 15C) and shutdown procedure with loss-of-offsite power assumed (HNP-2-FSAR supplement 15C and chapter 6) include the use of both residual heat removal (RHR) loops for shutdown cooling operation. If a single-active failure were applied to the RHR system, leaving only one RHR loop available for shutdown cooling operation, the plant could still be brought to a cold shutdown condition, although more time would be required. This condition is based on the assumption that the suppression pool temperature limit does not have to be maintained, since no other accident is postulated to occur concurrently with the high-energy line break.

3. Blowdown data are provided in table N.5-1. Equipment required and/or preferred for use in bringing the reactor to a safe shutdown is specified in table N.5-2.

4. Detailed reviews were made at the site to verify the results and conclusions set forth in the individual analyses below. Vent areas between compartments were critically checked, as were proximity of safety-related components to source piping. The compartment volumes and vent areas used for the purposes of the original analyses (inputs and results reflected in later subsections) may slightly differ from the analyses performed after the performance of the original analysis. However, the differences have been evaluated with no significant change to the results of the original analyses.

5. The primary containment structural integrity was evaluated following each postulated failure. In each pressure calculation, the external pressure in the drywell air gap and against each appurtenance (e.g., personnel lock) and the torus was calculated. Generally, factors of safety, with respect to the initiation of buckling, of two or greater, were verified by the containment vendor. In all calculations, other structural elements were found to be more limiting with respect to ultimate failure than the primary containment with respect to the initiation of buckling.

6. No hatches or block walls were allowed to fail in such a manner as to create missiles.

7. The essential motor control centers (MCCs) are located in the reactor building on the el 130 ft floor. These MCCs have been evaluated with respect to proper operation and survival during and after the postulated accident. As indicated in the pressure temperature transient analysis summaries given by line break below, the main steam line break (MSLB) yields the highest peak temperature and high-pressure coolant injection (HPCI) steam line break longest duration of temperature above original ambient. The evaluation indicated that these MCCs could operate in the resultant environment following either postulated accident.

   The evaluation was made by calculation of the effects of the differential pressure applied across the exposed sides of the MCC and by analysis of all the components exposed to the effects of temperature and humidity. In addition to the effects of pressure, temperature and humidity on each individual component, full consideration was given to the sequence and duration of operation required for each component during reactor shutdown operation.

   The analysis of the essential components in the MCCs was based on a maximum operating time of 135 s for any one of the components during the period of shut down operation which spans ~ 5 h. Since the limiting maximum temperature for continuous safe operation of any of the insulating materials is 257°F, no damage to insulation occurs. The essential components are constructed of materials, including insulation, which have low moisture absorption properties. For these reasons, the temperature and humidity resulting from the accident will not impair the operation of the essential components.

   The differential pressure across the exposed sides of the MCCs is not sufficient to impair the structural integrity of the enclosures. The resultant pressure effects, combined with the temperature and humidity effects, are not of a magnitude to impair proper operation of any of the essential components. Vendor verification of these conclusions was obtained.

   A test was performed to qualify the MCCs under the worst calculated conditions for peak temperature and pressure (MSLB) and long-term temperature (HPCI steam line break). The MCCs are energized in a manner approximating the shutdown operation as indicated in HNP-2-FSAR supplement 15C and chapter 6.

Break locations for high-energy and moderate-energy piping outside the containment are provided in HNP-1 stress calculations which were reviewed and revised (if necessary) as part of the overall pipe stress reanalysis effort performed for NRC Inspection and Enforcement Bulletin (IEB) 79-14. These HNP-1 stress calculations also provide stress intensities for the various data points analyzed on the high-energy and moderate-energy piping.

N.5.1 MAIN STEAM LINE BREAK

As shown in figures N.5-1 and N.5-2, there are 4 main steam lines that are routed from the primary containment through the main steam pipe chase at el 130 ft in the reactor building to the turbine building. Pipe failure in the main steam system outside the primary containment is discussed in HNP-2-FSAR chapter 15. The design of the main steam lines, isolation valves, and flow restrictors is discussed in chapter 4.

The main steam lines automatically isolate in the event of a postulated failure. A break is sensed by high steam line flow, high temperature in the pipe chase, or low reactor water level. Descriptions of these automatic isolation systems appear in section 7.3.

N.5.1.1 MSLB in Main Steam Pipe Chase

In the main steam pipe chase, located at el 130 ft of the reactor building, west of the drywell, each of the 4 main steam lines is anchored immediately downstream of the outboard isolation valve. In addition, there is a four-direction (including rotation) restraint at the containment penetration. Tie rods are provided between the anchor and the restraint to prevent separation of the pipe at any break occurring between the anchor and the restraint. The entire anchor and restraint system is designed to withstand pipe rupture loads as defined below. The purpose of this restraint system is to protect the containment penetration from pipe rupture in this area and to isolate the outboard isolation valve from pipe break, thermal expansion loads, and earthquake effects in the piping downstream of the anchor. (See figures N.5-1 and N.5-2.)

In addition, the penetration of each pipe through the reactor and turbine building walls serves as an effective pipe whip restraint. There remains ~ 33 ft of pipe between the anchor and the wall in each of the 4 lines which are not restrained against pipe movement in the event of pipe rupture.

The design of anchors and restraints for pipe rupture loads is based on the following criteria:

A. Design Loads

The design loads for the pipe anchors and restraints and support steel design is determined by the following formula:

$F = K_1 K_2 PA$ lb

where:

K_1 = thrust multiplication factor for the change in momentum due to a two phase flow. A value of 1.20 is used.

K_2 = dynamic load factor to account for the effects of rapidly applied load. A value of 1.25 is used.

P = operating pressure of the fluid (psig).

A = pipe internal area (in.^{2}).

B. Design Stress

Restraints and supporting steel are designed in accordance with the American Institute of Steel Construction (AISC) Code, Sixth Edition, using a 50% increase in code allowable stresses and using forces as described in A above.

C. No additional factor is used for impact effect since there is negligible clearance between the pipe and the restraint and none in the case of the anchor.

Of the pipe breaks which are postulated to occur in accordance with the AEC criteria, 13 are in the pipe chase; 8 of these are at the terminal ends on either side of the anchors on the 4 main steam lines, and the other 5 are at data points shown in HNP-1 stress calculations.

The targets of concern in this room are the HPCI injection line and the main steam isolation valves (MSIVs). The HPCI injection line rises through the floor of the pipe chase directly under one of the feedwater lines and connects to the bottom of the feedwater line downstream of the outer feedwater isolation check valve. The feedwater line from the containment penetration to the check valve is considered part of the target. The anchors and restraints on the main steam lines in this area prevent these lines from moving toward this target. A fluid jet from any of the postulated breaks is either not directed toward this target or is prevented from damaging the target by physical separation and by the intervening anchor frames which span the width of the room. The MSIVs are protected from pipe movement and jet effects by these same features. The temperature effects of an MSLB in the pipe chase do not prevent the closure of the MSIVs since they fail closed on loss of air or electrical power.

The main steam and feedwater anchor frames are made up of wide flange beams with the openings between the beam flanges filled in on each side with 1-in.-thick plate. A third 1-in.-thick plate extends through the middle of each frame in between the beams. These frames are depicted in detail in figures N.5-1 and N.5-9. The only openings in these frames are immediately around each pipe. These openings are just large enough to accommodate the pipe insulation. The open area is further reduced by the pipe trunions which anchor the pipes to the frames.

In considering the direct effects of an MSLB, it is necessary to determine whether such a break could cause a subsequent break in another main steam line or a feedwater line and thereby increase the blowdown. The locations of main steam and feedwater lines relative to each other is illustrated in figures N.5-1 and N.5-2. In evaluating the possibility of subsequent breaks as a direct effect of an MSLB, the following argument is presented:

A. Any break at the terminal end on the upstream side of the anchor will not result in pipe movement because of the anchor restraint system described above.

B. A longitudinal break at the terminal end on the downstream side of the anchor will not result in pipe movement since the anchor prevents movement.

C. A circumferential break at any of the break locations will not cause the pipe to move toward the other steam or feedwater lines. Only a longitudinal break can move a steam line toward the other lines since all of the lines lie in parallel planes.

D. The stresses at the other postulated break locations have been identified as to whether they are axial or hoop stresses. The hoop stress arises from internal pressure. The axial stresses result from pressure, dead weight, earthquake, and thermal expansion. Each of these stresses is available for each data point from the various analyses of these pipes. The total hoop stress and the total axial stress at each of the break locations of concern are separately tabulated in HNP-1 stress calculations. The total axial stresses in each case are more than twice as high as the total hoop stresses. It is concluded that any break at these locations would be a circumferential break since this is the type of break which would result from axial stress. Therefore, movement toward any other line is precluded.

As a result of the detailed system analysis of the HPCI steam line break, a 200-ft^2 grated vent opening was provided in the floor of the pipe chase room. (See paragraph N.5.3.1, item B.) The postulated break at data point 386, which is at the lower elbow on one of the main steam lines has been evaluated to determine whether it could result in jet impingement on the torus through the vent opening.

As explained in D above, circumferential breaks are postulated. The break at data point 386 is postulated to occur at the fitting-to-pipe weld at either the upstream or the downstream end of the elbow. The pipe movement which would result from either of these breaks is illustrated in figure N.5-10. The fluid jets which issue from the broken ends of the pipe are assumed to expand uniformly at a half angle of 15 degrees as given in Section 223 of BN-TOP-2 for steam blowdown situations. The fluid jet issuing from the upstream end of the pipe in each of the two cases illustrated in figure N.5-10 is not directed toward the floor. The fluid jet issuing from the downstream end of the pipe in case 1 is completely intercepted by the concrete floor. The fluid jet issuing from the downstream end of the pipe in case 2 is almost completely intercepted by the floor with only a narrow edge of the jet passing through the opening and impinging on the torus at a shallow angle averaging 23 1/2 degrees on the curved surface of the torus. This occurs at a distance of ~ 27 ft from the break. At this point, the pressure is reduced by the ratio of the break area to the area of the jet at 27 ft and also by the angle of impingement. Combining the applicable equations in BN-TOP-2, the pressure exerted on the small area of the torus which the edge of the jet contacts is evaluated as follows:

$$P_2 = P_1 \frac{A_1}{A_2} \sin\theta$$

where:

P_2 = pressure of jet at distance of 27 ft from break.

P_1 = pressure of jet at break.

A_2 = area of jet at distance of 27 ft.

A_1 = area of jet at break.

θ = impingement angle at target (23 1/2 degrees).

The calculated resultant pressure is about 5 psi, which acts over an area of ~ 58 ft^2. This pressure is less than the localized pressure which would initiate buckling. A uniform pressure of at least 8.3 psi would initiate buckling of the torus. The impingement from the jet described above is also directly over a ring support on the torus which is stronger than the midsection.

The pressure temperature transient analysis for a MSLB in the pipe chase was performed in accordance with the procedure described in section N.4.4 and with the blowdown data provided in figure N.5-11 and table N.5-1. The existing vent area out of the pipe chase was found to be sufficient to maintain the differential pressure between the pipe chase and the reactor building to less than the limiting value of 10 psid; however, the absolute pressure in the reactor building at el 130 ft was found to be greater than the limiting value of 500 lb/ft^2. As a result of this evaluation, modifications were designed to enable pressure relief directly and indirectly to the turbine building. The additional vent area provided included 75 ft^2 directly to the turbine building from the pipe chase, 200 ft^2 from the pipe chase to the heating, ventilation, and air-conditioning (HVAC) room directly above the pipe chase at el 164 ft, 269 ft^2 of vent area from the HVAC room directly to the turbine building, and 200 ft^2 of grated vent area in the el 129 ft 0 in. floor of the pipe chase to the torus chamber room below. All vents to the turbine building have blowout panels designed to "pop-off" and provide clear openings. The vent area to the HVAC room above the pipe chase is open; however, a vertical steel shield plate is provided to maintain accessibility to the HVAC room. These modifications were made prior to commercial plant operation. The initial conditions and final results of the pressure analysis, with the proposed modifications, are summarized as follows:

A. Initial conditions

Temperature (°F)	105	
Pressure (psia)	14.7	All compartments
Relative humidity (%)	50	
Room volumes (ft^3)		
Pipe chase	26,070	
HVAC room	4.6×10^4	
Floor el 130 ft	2.6×10^5	
Drywell air gap	3,000	
Torus chamber room	2.92×10^5	
Vent areas (ft^2) from pipe chase to:		
Floor el 130 ft	442	
HVAC room	200	
Turbine building	75	
Drywell air gap	12.5	
Torus chamber room	200 (grated)	

B. Results

Maximum pressure (psia) in:	
Pipe chase	18.0
Floor el 130 ft	16.7

HVAC room	16.5
Drywell air gap	16.7
Torus chamber room	18.0

Maximum differential pressure (psid):
Occurs between pipe chase and floor el 130 ft at 4 s - 1.3

Maximum temperature floor el 130 ft = 240°F (2.7 s)

Long-term temperature response for floor el 130 ft indicates that the temperature drops to 140°F within 23 min after the break.

The above pressure temperature calculation was performed using 15 separate compartments. The only vent area from the reactor building directly to atmosphere are the tornado relief vents in the roof, which amount to 600 ft^2 and which relieve at 55 lb/ft^2 differential pressure.

The only safety related equipment in the vicinity of the HVAC room at el 164 ft in the reactor building are the standby gas treatment system (SGTS) filter trains located in a compartment just north of the HVAC room. These filter housings and all associated piping are designed to take 2 psig external pressure, which is above the calculated value of 1.8 psig. The peak calculated temperature of 260°F does not adversely affect the SGTS; however the temperature setpoint for actuation of the water spray system has been set at 300°F. The SGTS is not required following a MSLB.

An analysis of postulated cracks in the main steam pipe chase resulted in no potential problems with respect to jet impingement on piping structural elements or electrical cable. The other environmental effects are much less severe than the postulated break. A leak is detected by the temperature sensors located in the pipe chase, which initiate isolation of the main steam lines.

N.5.1.2 MSLB in Turbine Building

All main steam piping within the turbine building is physically separated from structures, systems, and components important to reactor safety by both distance and structural barriers. More information regarding this is provided in item 4, subsection N.3.2. Location of the main steam lines in the turbine building with respect to the control complex in the control building is shown in figure N.5-12.

The pressure temperature transient analysis was performed for a MSLB in the turbine building using eight separate compartments. The only vents directly to the atmosphere from the turbine building are the tornado relief vents in the roof which amount to about 3000 ft^2 and which relieve at 50 lb/ft^2 differential pressure. As indicated by the results summarized below, no pressure or temperature problems were identified in the turbine building.

A. Initial Conditions

Temperature (°F)	105	All compartments

Pressure (psia)	14.7
Relative humidity (%)	50

Room volumes (ft^2):
Condenser room el 130 ft containing steam lines - 6.0×10^5

Floor above el 164 ft - 3.3×10^6
Vent areas (ft^2) from condenser room at el 130 ft to:
Floor above el 164 ft - 1116
Condenser room below el 130 ft - 3613

B. Results

Maximum pressure (psia) in:	
Condenser room at el 130 ft	15.4
Floor above el 164 ft	14.9
All compartments below el 130 ft	15.4

Maximum temperature (°F) in:	
Condenser room at el 103 ft	246
Floor above el 164 ft	124
All other areas	< 120

As was the case for the pipe chase, postulated cracks will not result in any adverse effects on safety-related components.

N.5.1.3 Analysis of Shutdown Capability

The ability to shut down the reactor safely following a postulated main steam line failure was analyzed using the guidelines presented in HNP-2-FSAR supplement 15C. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table N.5-2. The required equipment is operable with the required redundant components available.

For a MSLB outside the primary containment, the reactor is automatically scrammed by turbine control valve (TCV) fast closure assuming an LOSP, shutting of the MSIV, or by low reactor pressure vessel (RPV) water level 3. The MSIVs are closed automatically by high steam flow, high temperature in the vicinity of the pipe chase, or low-low reactor water level 1. The RPV isolation is completed by the closure of the MSIVs. After isolation of the RPV, pressure increases until the setpoint of the safety relief valves is reached (1080 psig).[a] Pressure is then automatically relieved by the discharge of steam to the pressure suppression pool.

RPV water level is maintained by automatic operation of the HPCI system and/or operation of the reactor core isolation cooling (RCIC) system. Assuming that the hypothesized single active component failure disables the HPCI system, RPV water level will be maintained by operation of the RCIC system.

The additional operations required to bring the reactor to a safe shutdown condition are described in appendix B and chapter 6. An assumed LOSP is considered to be effective at the time of the initial pipe break.

The residual heat removal service water (RHRSW) system and the plant service water (PSW) system are not affected by the postulated MSLBA. Therefore, adequate component and room cooling for the equipment identified in table N.5-2 is available.

N.5.2 FEEDWATER LINE BREAK

As shown in figures N.5-1 and N.5-2, and drawing no. H-11064, there are two feedwater lines that are routed from the primary containment through the main steam pipe chase to the turbine building. Since the routing of these lines follows the routing of the main steam lines, several analogies can be drawn with respect to analyses performed on the main steam lines. The blowdown energy released from a feedwater line break is about a factor of 6 less than an MSLB. The pipe whip and jet impingement loads are also less limiting than for an MSLB.

The pressure at the discharge of the feed pumps during normal conditions is ~ 1310 psig and is about 1095 psig at the reactor inlet nozzle and the temperature is about 392.4°F; thus, the feedwater system is considered a high-energy system. Backflow from the reactor vessel to the break is prevented by closure of the feedwater check valves coincident with flow reversal; thus, flow through the break would be from the feed pumps only. It is assumed that water from both feed pumps would discharge through the break. As soon as the postulated break occurs, the discharge pressure of the pumps decreases and the flow increases until pump runout occurs. It is conservatively assumed that the steam-driven feed pumps continue running until the steam supply is exhausted or terminated by closure of the MSIVs. This assumption implies that offsite ac power is not lost for this accident. If offsite ac power is lost, the electric motor-driven condensate booster pumps would shut down, which would cause the feed pumps to trip due to low suction pressure.

Postulated critical size cracks have been evaluated with no potential jet impingement problems identified anywhere along the feedwater lines. Other environmental effects are considerably less significant than those for the main steam lines.

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a. Analyses demonstrate the shutdown capability is not significantly affected by an increase in SRV setpoints or an increase in thermal power to 2804 MWt.

N.5.2.1 Feedwater Line Break in Main Steam Pipe Chase

The postulated breaks on these lines in this room are on either side of the anchor (terminal ends). Each of these two pipes is anchored and restrained in the same manner as described in subsection N.5.1 above for the main steam lines. The anchors and restraints are designed for pipe rupture loads. A break at the terminal end of either of these lines on either side of the anchor would be upstream of the isolation check valve. The feedwater line to which the HPCI injection line connects is prevented from moving by the restraint at the containment penetration if it should break on the downstream side of the anchor. A break on the upstream side of the anchor would not direct the broken pipe toward the HPCI line. A fluid jet from either of these breaks would not be directed toward the HPCI line. The HPCI injection line would, therefore, not be damaged by a feedwater line break.

The MSIVs would not be damaged by the postulated breaks. The fluid jet from a break on the downstream side of the anchor is not directed toward the MSIVs. The pipe is prevented from separating at this location by the anchor restraint system. The break on the upstream side of the anchor does not direct the broken pipe toward the valves. The fluid jet from the broken pipe is prevented from reaching the valves by intervening structures.

A conservative analysis of a feedwater line break in the main steam pipe chase, assuming no LOSP, was performed to evaluate the effects of reactor building flooding. An estimated inventory of 200,000 gal was used as discussed in the footnotes to table N.5-1. The main concern was allowing water to enter the RHR corner rooms via stairwells. The stairwells to these rooms, located on the east side of the building, are the furthest opening away from the pipe chase room. The pipe chase room is recessed 1 ft and has a drain; however, the 200-ft^2 vent in the floor drains the water into the torus chamber area below, which is designed for flooding. For this reason, little or no water is expected to reach the RHR corner rooms.

N.5.2.2 Feedwater Line Break in Turbine Building

All feedwater piping within the turbine building is physically separated from structures, systems, and components important to reactor safety and is also separated from these systems and components by Seismic Class 1 and radiation shield walls most of which are 5-ft 0-in. thick. No feedwater line failure in the turbine building prevents the safe shutdown of the plant.

The problem of turbine building flooding has been addressed in chapter 11. The inventory of water considered in the analysis is much greater than that amount possible from the feedwater line break; therefore, the consequences of a feedwater line break are less severe and are enveloped by the case addressed in chapter 11. In summary, flooding from a feedwater line break in the turbine building does not adversely affect the ability to shut down the reactor.

N.5.2.3 Analysis of Shutdown Capability

The structures, systems, and components required for the safe shutdown of the plant following a postulated feedwater pipe break are presented in table N.5-2. HNP-2-FSAR section 15.2

provides a detailed parametric analysis of the transient conditions following the loss of feedwater flow (LOFW).

As has been pointed out, it is more conservative for this accident to assume that offsite ac power is not lost than to assume it is lost. If offsite power was lost coincident with the feedwater pipe failure, the reactor would be scrammed by the fast closure of the TCVs, low RPV water level 3, or closure of the MSIVs. If offsite power was not lost, the scram is initiated by low reactor water level or MSIV closure. RPV isolation is initiated by low RPV water level 3 and completed by MSIV closure, which is initiated by high main steam pipe chase temperature, low steam line pressure, or manual action.

After the reactor has been scrammed and the RPV isolated, the sequence of events is similar to that given above for the MSLBA. The analysis of equipment availability following an MSLBA is applicable to a feedwater pipe break accident as well.

N.5.3 HPCI STEAM LINE BREAK

As shown in figure N.5-3, the HPCI steam line leaves the primary containment just above el 130 ft and is routed to the pipe penetration room on the east side of the drywell. It penetrates the floor at el 130 ft and is routed through the torus room to the HPCI room north of the reactor building proper. Postulated break locations and the table of stresses are provided in HNP-1 stress calculations.

A break at either of two postulated break locations in the torus room could result in damage to a PSW line, which is required when RHR pump or room cooling is required. A postulated loss of function of this service water line would only serve to make one loop of the RHR system unavailable. The other RHR loop would be unaffected. In addition, a break at one of several of the postulated break locations in the torus room could cause this line to strike and possibly penetrate the top of the suppression chamber (air space). A hole in the top of the suppression chamber would not prevent the safe shutdown of the reactor.

Jet impingement from a critical size crack or break in this line has been evaluated at any location. No targets of concern have been identified which would be potentially damaged. A steam leak in the torus room from a HPCI steam line or any other line is detected by differential temperature switches in the ventilation system supply and exhaust. This temperature detection system has the required redundancy to accept any single-active failure and still performs its function.

N.5.3.1 <u>Pressure Temperature Analysis</u>

The pressure temperature transient analysis was performed for the pipe penetration room, the torus room, and the HPCI turbine pump room. The results and conditions of these studies are summarized below:

A. HPCI Room

1. Initial conditions

Temperature	105°F
Pressure	14.7 psia
Relative humidity	50%
Volume	52,015 ft^3
Vent area to atmosphere	81 ft^2

2. Results

Maximum pressure in HPCI room - 26.6 psia

3. Discussion

The vent area to the atmosphere is provided by the concrete hatch in the roof, which lifts under its own weight, conservatively estimated to be 4.5 psi. The ultimate, 90% structural capacity of the room is 13.9 psig, and the resultant maximum pressure in the room is 11.9 psig as indicated above.

A time-history dynamic analysis was performed on the roof hatch to evaluate the effects of allowing it to lift. The results of the analysis indicate the hatch would not cause damage that would preclude a safe shutdown. It is probable that damage could occur to the HPCI room roof; however, use of the system would be lost with the break.

B. Torus Room

1. Initial Conditions

Temperature	105°F
Pressure	14.7 psia
Relative humidity	50%
Volume	2.92×10^5 ft^3
Vent area to:	
NW corner room	9.0 ft^2
SW corner room	1.4 ft^2
Reactor building above el 130 ft	200 ft^2(grated) and 18 ft^2 (torus room access plugs)

2. Results

Maximum pressure in torus room - 16.7 psia
Maximum ΔP across RHR (east) corner room walls - 1.6 psid

3. Discussion

The above results were determined with some plant modifications. These modifications include blocking the vent area to the RHR (east) corner rooms by sealing around pipe penetrations in order to maintain a safe environment in these rooms. The 42-ft^2 hatch above the RCIC corner room leading to el 130 ft above was replaced with grating, and a 200-ft^2 (grated) opening was provided to the main steam pipe chase above the torus chamber room. As indicated in the results of this analysis the maximum pressure in this compartment is well below the external pressure that will initiate suppression chamber buckling (> 8 psi), and the maximum differential pressure across the RHR corner room walls is less than the 2 psid ultimate (90%) structural capacity.

C. Pipe Penetration Room at Floor Elevation 130 ft

1. Initial Conditions

Temperature	105°F
Pressure	14.7 psia
Relative humidity	50%
Volume vent area to:	5468 ft^3
floor el 130 ft	112 ft^2
drywell air gap	11.2 ft^2

2. Maximum pressure in pipe penetration room - 19.1 psia
Maximum pressure floor el 130 ft - 14.8 psia
Maximum pressure in drywell air gap - 15.3 psia

3. In order to obtain the acceptable results given above, it was necessary to convert proposed hatches to grating, thus providing an additional 82 ft^2 of vent area. The maximum pressure against the containment personnel lock located in this room is about a factor of 2 below the pressure to initiate buckling. The concrete block wall directly opposite the containment personnel lock is reinforced with removable steel plates to prevent the pressure from blowing out the wall and creating missiles. The block wall is reinforced to take pressure well above that calculated.

The postulated full break of a HPCI steam line at the el 130 ft floor yields a peak calculated temperature of about 215°F on the el 130 ft floor. This temperature is conservatively calculated to drop to below 140°F within 1.4 h following the break. Thus, this postulated break represents the worst long-term temperature transient as referred to in section N.5, item 7.

Postulated critical cracks located anywhere along the steam line have no adverse effects on components required for safe shutdown. Environmental effects in the HPCI room and torus room are less severe than those for a break in these areas. Temperature sensors have been added to enable detection of a crack that would blowdown less than 300% flow in the pipe penetration room. Upon receipt of a high temperature signal from the sensor, the HPCI steam line isolation valves are closed. The setpoint is set low enough to detect a significant leak in the steam line but high enough to avoid spurious isolation. In addition, the radiation monitors in the reactor building ventilation system exhaust duct, and the area radiation monitors would provide backup information to the operators in the event of a leak.

N.5.3.2 Analysis of Shutdown Capability

The ability to safely shut down the reactor following a postulated HPCI steam line failure was made using the guidelines of HNP-2-FSAR supplement 15C. The structures, components and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table N.5-2. All of the required equipment is operable with the required redundant components available.

For a postulated break in the HPCI steam line, it is possible that a reactor scram could occur from RPV low water level 3. In the event that no scram results before isolation of the HPCI steam line is effective, a normal shutdown of the plant would be followed. This shutdown would be as described in HNP-2-FSAR supplement 15C. A shutdown of this nature would be conducted according to the demands of the power system and in compliance with the Technical Specifications.

If a reactor scram should occur concurrent with the postulated LOSP, the main condenser would act as a heat sink until the MSIVs were closed. Closure of the MSIVs could result from RPV water level reaching the low RPV water level 1 trip point initially or subsequently, steam line low pressure, loss of main condenser vacuum, or operator action. Closing of the MSIVs would conserve coolant inventory in the RPV and would not require operator action in < 10 min, assuming automatic closure had not occurred. Following closure of the MSIVs, reactor shutdown would follow the method described in HNP-2-FSAR supplement 15C and chapter 6.

Break isolation is accomplished by automatic isolation of the HPCI steam line initiated by high steam flow and/or low pressure in the HPCI steam line.

Although preferable for use in normal shutdown procedure, the HPCI system is not required in order to shut down the unit. If the RCIC system is available, it is able to maintain RPV water level until the operator initiates depressurization of the reactor. If a single-active component failure causes the RCIC system to be unavailable, there is sufficient water inventory in the RPV to ensure that the water level stays well above the top of the active fuel for the 10 min after the break, during which no manual action is assumed. The operator initiates depressurization of the reactor at 10 min after the break has occurred. After the RPV is depressurized, low-pressure coolant injection (LPCI) or core spray (CS) system is more than adequate to supply makeup water to the RPV.

Suppression pool cooling is accomplished by remote manual operation of the RHR System as detailed in HNP-2-FSAR supplement 15C and chapter 6.

N.5.4 RCIC STEAM LINE BREAK

The RCIC steam line penetration exits the primary containment into the main steam pipe chase and then penetrates the pipe chase floor at el 130 ft into the torus room below. It is then routed to the southwest corner room to the RCIC turbine. Postulated break locations and corresponding stresses are provided in HNP-1 stress calculations.

The only safety-related component in the vicinity of this line is an 8-in. PSW line. A break at any of the postulated break locations in the RCIC line does not direct this line toward the service water line.

A break at one of the postulated break locations could cause the RCIC steam line to strike the torus. It would not penetrate the torus because of its small size. The thickness of steel plate which could be penetrated by this line has been calculated by the ballistic missile formula and was found to be less than the thickness of the torus shell.

Critical cracks postulated to occur anywhere along this line do not result in damage to safety-related equipment or components and do not impair the capability to safely shut down the reactor. Leaks are detected by temperature instrumentation located in all compartments containing this line.

N.5.4.1 Pressure Temperature Analysis

The postulated failure of the RCIC steam line in the main steam pipe chase would have negligible effects compared to the failure of a main steam line. Similarly, a failure in the torus room would have less significant effects than a HPCI steam line failure in the same compartment. Critical cracks postulated to occur in these compartments would also be negligible compared to those for the larger lines. The initial conditions and results of the analysis performed for the RCIC southwest corner room are summarized as follows:

A. Initial Conditions

Temperature (°F)	105
Pressure (psia)	14.7
Relative humidity (%)	50
Room volumes (ft^3):	
RCIC corner room	2.8×10^4
Torus room	2.9×10^5
Reactor building above el 130 ft below refueling floor	8.8×10^5
Vent areas (ft^2) to:	
Torus room	1.4
Reactor building el 130 ft	42

B. Results

Maximum pressure (psia)	
RCIC corner room	15.8

The results indicate that the RCIC steam line break is not significant compared to the HPCI steam line break in the torus room and compared to either the MSLB or HPCI steam line break at the el 130 ft floor. The break in the corner room renders that room and the RCIC unavailable for service, but does not lead to a pressure or temperature problem in any other compartment.

N.5.4.2 <u>Analysis of Shutdown Capability</u>

The ability to safely shut down the reactor following a postulated RCIC steam line failure has been made using the guidelines of HNP-2-FSAR supplement 15C. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in table N.5-2. All of the required equipment is operable with the required redundant components available.

Failure of the RCIC steam line has minor effects on the nuclear boiler system; i.e., reactor scram, reactor vessel isolation or initiation of emergency core cooling system are extremely unlikely. The RCIC steam line is automatically isolated by high steam flow or RCIC steam supply line low pressure as specified Technical Specifications table 3.3.6.1-1. Consequently, the reactor shutdown would be as described in HNP-2-FSAR supplement 15C. Again, the shutdown procedure is according to power system demands and compliance with Technical Specifications.

It is possible that a break in the RCIC steam line in the main steam pipe chase might initiate closure of the MSIVs from their associated high temperature sensors. In this event, a reactor scram would result and an LOSP is assumed; shutdown procedure for this case would follow that provided in HNP-2-FSAR supplement 15C and chapter 6.

N.5.5 REACTOR WATER CLEANUP (RWC) LINE BREAK

The RWC system is described in section 4.9. The HNP-1 stress calculations show all postulated break points and a table of stresses for these points.

The high-energy portions of the system that are outside the primary containment are:

- From the primary containment to the outlet nozzle of the nonregenerative heat exchanger in the system supply line.

- From the discharge of the regenerative heat exchanger to the connection into the feedwater system in the return line.

A postulated failure in the cleanup system results in a single-ended failure. Check valves in the return line immediately upstream of the connection into the feedwater piping prevents backflow from the return side of the break. Automatic isolation of the RWC system is accomplished by signals listed in Technical Specifications table 3.3.6.1-1. Detailed descriptions of these isolation signals are provided in section 7.3. Blowdown data and isolation valve closing time for the cleanup system are given in table N.5-1.

It has been determined that a failure in the 3- or 4-in. cleanup lines at any location in the main steam pipe chase would not cause damage, either by pipe whip or jet impingement, from either a break or a crack, to the larger (14 in.) HPCI injection line. Intervening pipes and structures also prevent damage to the MSIVs.

The cleanup line passes near a cable tray containing safety-related cables at el 130 ft just outside the main steam pipe chase in the reactor building. Jet impingement from a critical size crack could damage these cables. A barrier has been provided in the area of proximity to the cable tray to prevent jet impingement on the cables. There are no postulated break locations in this area.

Jet impingement from a critical size crack at el 158 ft in the reactor building could possibly cause damage from pipe movement to the RPV level and pressure sensing lines for the Division II side of the reactor protection system (RPS). The sensing lines are 3/8-in. outside diameter tubes routed in a tray and are equipped with excess flow check valves to minimize leakage from a crack or break. Since the Division I RPV level and sensing lines would be unaffected by a RWC line failure, and are physically separated by distance and intervening structures, these lines are available to monitor the shutdown of the reactor. All active components associated with each division of these sensing lines are redundant, therefore, a single-active failure does not affect the monitoring functions.

N.5.5.1 Pressure Temperature Analysis

The pressure temperature transient analysis was performed for the compartments containing the pumps, heat exchangers, and phase separators at el 158 ft in the reactor building. A break or crack in either the main steam pipe chase or el 130 ft (crack only) of the reactor building results in pressures and temperatures less than those resulting from an MSLB. The initial conditions and results of the analyses performed at el 158 ft are summarized as follows:

A. Initial Conditions

Temperature (°F)	105	All compartments
Pressure (psia)	14.7	
Relative humidity (%)	50	
Room volumes (ft^3):		
RWC pump room	11,200	
RWC heat exchanger room	22,000	
Reactor building below refueling floor	8.8×10^5	
Vent areas (ft^2) from:		

Pump to heat exchanger room	200
Pump room to reactor building below refueling floor	42
Heat exchanger room to reactor building below refueling floor	23

B. Results

Maximum pressure (psia) in:	
Pump room	17.3
Heat exchanger room	17.3
Reactor building below refueling floor	15.4
Maximum temperature (°F) in:	
Pump room	219
Heat exchanger room	206
Reactor building below refueling floor	131

The limiting conditions are the pressures across the pump and heat exchanger room walls with respect to the reactor building floor el 158 ft. Since the pump room walls can take a pressure differential of 23 psid and the heat exchanger room walls can take 13.9 psid, based on 90% of ultimate, the results are well within these allowable limits.

N.5.5.2 Analysis of Shutdown Capability

The ability to safely shut down the reactor following a postulated RWC piping system failure was conducted using the guidelines of HNP-2-FSAR supplement 15C. The structures, systems, and components that must be available to ensure meeting the criteria for safe shutdown are presented in table N.5-2. Required equipment is operable with the required redundant components available.

A postulated rupture of the RWC system piping will probably not cause a severe enough transient on the nuclear boiler system to result directly in a reactor scram, reactor vessel isolation (other than isolation of the RWC system), or automatic initiation of the emergency core cooling system. However, if the transient is such that any of those functions are required, they will automatically be initiated by the appropriate setpoint being reached. The effect on the nuclear boiler system for this postulated break is similar to that resulting from the HPCI steam line break; consequently, the shutdown options would be as described for that event.

N.5.6 MODERATE-ENERGY LINE CRACKS

Moderate-energy lines were identified in paragraph N.4.1.2; postulated critical size cracks for these lines and their locations were discussed in paragraph N.4.2.2. Postulated critical size cracks for high-energy lines were discussed in subsections N.5.1 through N.5.5. The results of the analyses performed for moderate-energy lines are discussed by system below. The shutdown capability discussed in HNP-2-FSAR supplement 15C is not impaired by postulated cracks in any of the lines discussed.

N.5.6.1 Control Rod Drive (CRD) Return Line Cracks

The control rod drive hydraulic system return line (pump discharge) is a moderate-energy (nonflashing) line for which critical size cracks have been postulated. This line is routed from the CRD pump in the northwest corner room through the el 130 ft floor in the reactor building to the primary containment. Due to the cold water that might be expelled from a crack in this line, only jet impingement and flooding are of concern.

At the el 130-ft floor, the return line passes near a cable tray containing safety-related cables. Jet impingement from a critical crack could possibly damage these cables; therefore, a barrier is provided to prevent the jet from impinging on the cables.

A jet impingement barrier was also installed to protect the backup scram valves (C11-F110A, B) and the pilot valve (C11-F009) from the effects of a crack in the CRD system piping.

A flooding analysis was also performed. The northwest corner room is equipped with an instrument sump that alarms in the main control room (MCR) for a 3-gal/min leak. High flow and low pressure in the system resulting from a crack can be detected by various parameters that are indicated in the control room. The return line is equipped with check valves which prevent backflow from the reactor side of the crack. Flooding of the corner room would not be extensive during the 10-min period for which no operator action was assumed; and since the system is not required for safe shutdown, flooding is not considered a problem. Flooding at el 130 ft and above is considered less serious than similar problems for larger line breaks as discussed in subsections N.5.1 and N.5.2.

A crack in the CRD return line does not affect the safe shutdown of the reactor by normal shutdown procedure. This line is also not required for use in shutting down since the accumulators in the hydraulic control units maintains the system capability to scram without the use of the return line.

N.5.6.2 Auxiliary Steam Line Cracks

The auxiliary steam line is a moderate-energy (flashing) line used for various purposes in the reactor building. There is no flow in the line unless called upon for service; however, the line is pressurized during the cold winter months when it is used for plant heating.

Since a critical crack in this line would lead to steam emission only, jet impingement, pressure, and temperature are the environmental concerns. The steam lines pass in close proximity to a safety-related MCC for safeguard system valves at el 130 ft. Since jet impingement from a crack could possibly damage this MCC, a barrier plate is provided for protection. In the pipe penetration room at el 130 ft east of the drywell, impingement could possibly damage the flex cable to the operator of the outer isolation valve on the HPCI steam line. A barrier is provided to provide protection for this flex cable. No other locations were identified to have jet impingement problems.

A very conservative (upper envelope) steam pressurization analysis was performed for a critical size crack in this line el 130 ft in the reactor building. The initial condition at this location were: pressure - 14.7 psia, temperature - 105°F, relative humidity - 50%. All vent areas out of el 130 ft were neglected to simplify the analysis. The Bechtel computer code, COPATTA, was used using only walls and ceilings as heat sinks. The maximum resultant temperature was 140°F occurring at ~ 3 min after the crack occurs; the maximum resultant pressure was 2.3 psig occurring at ~ 4 min after the crack occurs. Considering the conservatism in the analysis, these results are not significant when compared to similar results for a MSLB or HPCI steam line break.

An auxiliary steam line is used for various purposes in the HNP-1 turbine building. This line is the same size (10 in.) as that used in the reactor building. An analysis of this line for environmental effects in the turbine building has resulted in no problems being identified. The amount and duration of blowdown is not sufficient to create a pressurization or temperature problem. This line was originally routed through the control building; however, it has been flanged off in the turbine building.

N.5.6.3 <u>RHRSW Line Cracks</u>

The RHRSW line is a moderate-energy line (nonflashing) used to provide cooling water to the RHR heat exchangers in the east corner rooms in the reactor building. The routing of this line in the river intake structure is shown in figure N.5-8. No jet impingement or flooding problems were identified for this line in the reactor building. A critical size crack in this line in one of the RHR corner rooms or the torus room is detected by the instrument sump in that room. A crack in either of the RHR corner rooms or in the torus room would not affect the redundant RHR loop in the other corner room.

The configuration of RHRSW and PSW piping in the river intake structure, as shown in figure N.5-8, indicates that very little physical separation could be obtained due to the size of the pump room. In order to provide protection from jet impingement to the RHRSW pump motors and associated equipment, stiffened steel barriers mounted on a structural steel frame are provided.

A postulated critical size crack in the RHRSW line does not affect the capability to shut down the reactor, nor does such a crack require a shutdown procedure beyond that described above for normal shutdown with one RHR loop. The shutdown procedure is as described in HNP-2-FSAR supplement 15C with the additional qualification discussed in section N.5, item 2.

N.5.6.4 Sampling Lines

Due to the fact that all sampling lines are < 1 in. in diameter, breaks in these lines are not considered in accordance with paragraph N.4.2.1. Some of the sample lines are high-energy lines and some are moderate-energy lines, so critical size cracks have been considered in the analysis in accordance with paragraph N.4.2.2.

The only sample lines that contain high-energy or moderate-energy fluid under normal plant conditions are:

A. RWC system sample line from the regenerative heat exchanger outlet - Normally, there is no flow in this line; however, it is pressurized to about 1201 psig from the sample point to the isolation valve in the sample station, and the water being sampled is greater than 130°F.

B. Reactor water sample line from recirculating pump discharge - Normally, this sample line is pressurized to about 1250 psig at about 550°F. The sample line has inboard and outboard containment isolation valves which automatically close after receiving an isolation signal.

C. Feedwater (2 sample lines) from the feedwater pipes upstream of the outboard check valves - Normally, these lines have continuous sample flow and are pressurized to about 1175 psig at 392.4°F.

D. Mitigation monitoring system (MMS) - Sample lines from recirculation system sample line outside of primary containment and a return line connecting to a drain line of the RWC system upstream of the RWC pumps. These connections are located downstream of the double containment isolation valves in the recirculation and RWC systems. Double manual isolation valves and a bypass line are installed for use when the MMS (also called durability monitor) is not in use.

Two of these sample lines (A, B) are routed in the same vicinity at el 158 ft in the reactor building. The piping used for these sample lines is 1/4-in. outside diameter stainless steel tubing with a wall thickness of 0.065 in. These lines are routed in Seismic Class 1 tubing trays which reduces the possibility of physical damage to the sample lines. All sample lines in the reactor building are designed to Seismic Class 1 standards.

The two feedwater sample lines originate in the main steam line tunnel above el 147 ft in the turbine building and are routed north, dropped to the base el 112 ft, and then routed south to the sample station. No safety-related equipment is located in the vicinity of these lines. These lines are 3/8-in. outside diameter stainless steel tubing with 0.065-in. wall thickness and are also routed in tubing trays.

A critical size crack in any of these sample lines does not result in any direct effects on structures, systems, or components required for shutdown. Jet impingement, pressure, and temperature effects would be negligible due to the small size of the sample lines and the fact that they are completely enclosed in protective channel.

A discussion of automatic isolation of the reactor water sample lines in the event of their failure is provided in section 7.3. Sample lines identified above in B can be isolated by closing the RWC system supply line isolation valve. The MMS system is isolated when the reactor water sample line and the RWC system supply line are isolated. The feedwater sample lines are isolated remotely by shutting down the reactor feedpumps (after shutting down the reactor and closing the MSIVs).

The indications available to the operator that an RWC, MMS, or reactor water sample line failure has occurred are:

A. A temperature sensor in the RWC equipment rooms indicates high ambient temperature, and the RWC equipment room ventilation air inlet and outlet high differential temperature sensor indicates leaks in either the RWC or reactor water sample lines which are routed in these areas. The trip setpoints for these are between 100 and 150°F and 0 and 100°F, respectively. A discussion of these indications is provided in section 7.3.

B. Reactor building ventilation exhaust high-radiation alarm - Section 7.12 describes the operation of this system. A sample line failure results in higher than normal radiation levels in the reactor building ventilation exhaust which may initiate an alarm in the MCR and automatically initiate isolation of the secondary containment.

C. Area radiation monitor alarm - There is an area radiation monitor in the vicinity of the sample station on the el 158 ft floor. In the event of a postulated sample line failure, the general area radiation levels may rise and result in an alarm in the MCR.

A postulated failure of the feedwater sample lines in the main steam tunnel may result in a high temperature indication in the turbine building leak detection system.

N.5.7 RADIOLOGICAL CONSIDERATIONS

The principal radiological concerns for a postulated high-energy or moderate-energy line failure outside primary containment are the extent of exposures to an individual located at the site boundary and an operator located in the MCR. The radiological consequences associated with HPCI and RCIC breaks assuming time delays in area high-temperature isolation logic and a 300% rated flow for the system were compared to the consequences of an MSLB. The following results were calculated:

- RCIC steam line < 0.30% of main steam line dose.
- HPCI steam line < 1% of main steam line dose.

The MSLB accident outside primary containment is a design basis accident and the radiological consequences are discussed in detail in HNP-2-FSAR section 15.3.

A failure in the feedwater line is not of concern with respect to radioactive releases, and a failure of a RWC line is negligible when compared to the MSLB due to rapid isolation, much less discharge volume and less favorable transport mechanisms. Previous analyses demonstrate that the LOCA is the limiting event for radiological exposures to operators in the MCR. Therefore, for power uprate conditions (2804 MWt and reactor operating pressure increase to 1060 psia), only the LCOA was analyzed for MCR radiological exposures. An evaluation of exposure to control room personnel is discussed in HNP-2-FSAR section 15.3. The relationship of exposure to control room personnel from the other high-energy line breaks to that of the MSLB is similar to the relationship for site boundary doses. None of the moderate-energy lines contain significant radioactivity, and no failure in these lines could cause discharge of reactor coolant. It is concluded that any high energy or moderate-energy line failure outside the primary containment does not result in radiation exposures that exceed allowable limits to control room personnel or the general public.

TABLE N.5-1

BLOWDOWN DATA FOR HIGH-ENERGY LINE BREAKS

High-Energy Line	Time After Break (s)	Blowdown [(a)] Mass Flow (lb/s)	Blowdown [(a)] Energy (Btu/lb)	Blowdown Time Interval[(b)] Valve Closing Time (s)	Blowdown Time Interval[(b)] Signal Delay Time (s)	Blowdown Time Interval[(b)] Total Interval (s)
Main Steam[(d)]	0	5300	1191.5	5.0	0.5	5.5
	2.75	4500	1191.5			
	2.76	19,600	589.3			
	4.0	19,500	589.5			
	5.5	0	589.5			
HPCI Steam	Constant	3629	785.7	57.0	13.0	70.0
RCIC Steam	Constant	336	1189.9	25.0	13.0	38.0
RWC[(g)]	Constant	1448	550.0	30.0	13.0	43.0
Feed-water[(d)]	Constant	3012[(e)]	362.6[(e)]	(f)	(f)	(f)

a. Where applicable, a mixture quality of 7% is assumed for the mixture portion of the blowdown.
b. Valve closing times are the maximum allowable as specified in the Technical Requirements Manual. Signal delay times for isolation valves other than the MSIVs are conservatively taken as 13 s, even though some isolation valves are dc operated and would have delays of only 3 s or less. The 13-s signal delay is based on the time for diesels to reach capacity. This is generally conservative, since for some of these systems no LOSP is assumed or expected for a line break.
c. Feedwater line break in main steam pipe chase (18-in diameter, schedule 120 line).
d. See figure N.5-1.
e. Duration of this blowdown rate will probably be < 8 s. Following the break, the MSIVs will close cutting off steam supply for running the reactor feed pumps. The pumps will run out; since the MSIVs close in 5.5 s, the pumps will run out at about 8 s following the break.
f. E above discusses the blowdown interval which would occur with an LOSP; however, the worst case for flooding effects would occur without an LOSP. For this case, the condensate and booster pumps would continue to pump water out of the condenser hotwell. Assuming that the condensate storage tank continued to provide makeup water to the hotwell, it would take < 9 min to drain the hotwell to a level that would not supply the condensate pumps with sufficient NPSH and would cause the condensate booster pumps to automatically trip on low suction pressure. The total water inventory from this situation would be < 200,000 gal, which would be less than the AEC temperature-pressure criteria (nonflashing).
g. The high energy line break mass and energy release data were originally supplied by GE under GE letter SJ-73-39, dated January 26, 1973. GE letter GE-HATCH-TPO-022, dated May 17, 2002, and GE-HATCH-TPO-026, dated May 28, 2002, indicated that the mass and energy release data for the RWC lines were based on saturated liquid conditions and are nonconservative, since the RWC lines contain subcooled liquid. The mass and energy release data have been reevaluated and it has been concluded that the mass and energy release data supplied by GE originally are bounding.

TABLE N.5-2 (SHEET 1 OF 3)

EQUIPMENT REQUIRED AND/OR PREFERRED FOR USE IN REACTOR SHUTDOWN FOLLOWING HIGH-ENERGY LINE BREAK OUTSIDE PRIMARY CONTAINMENT

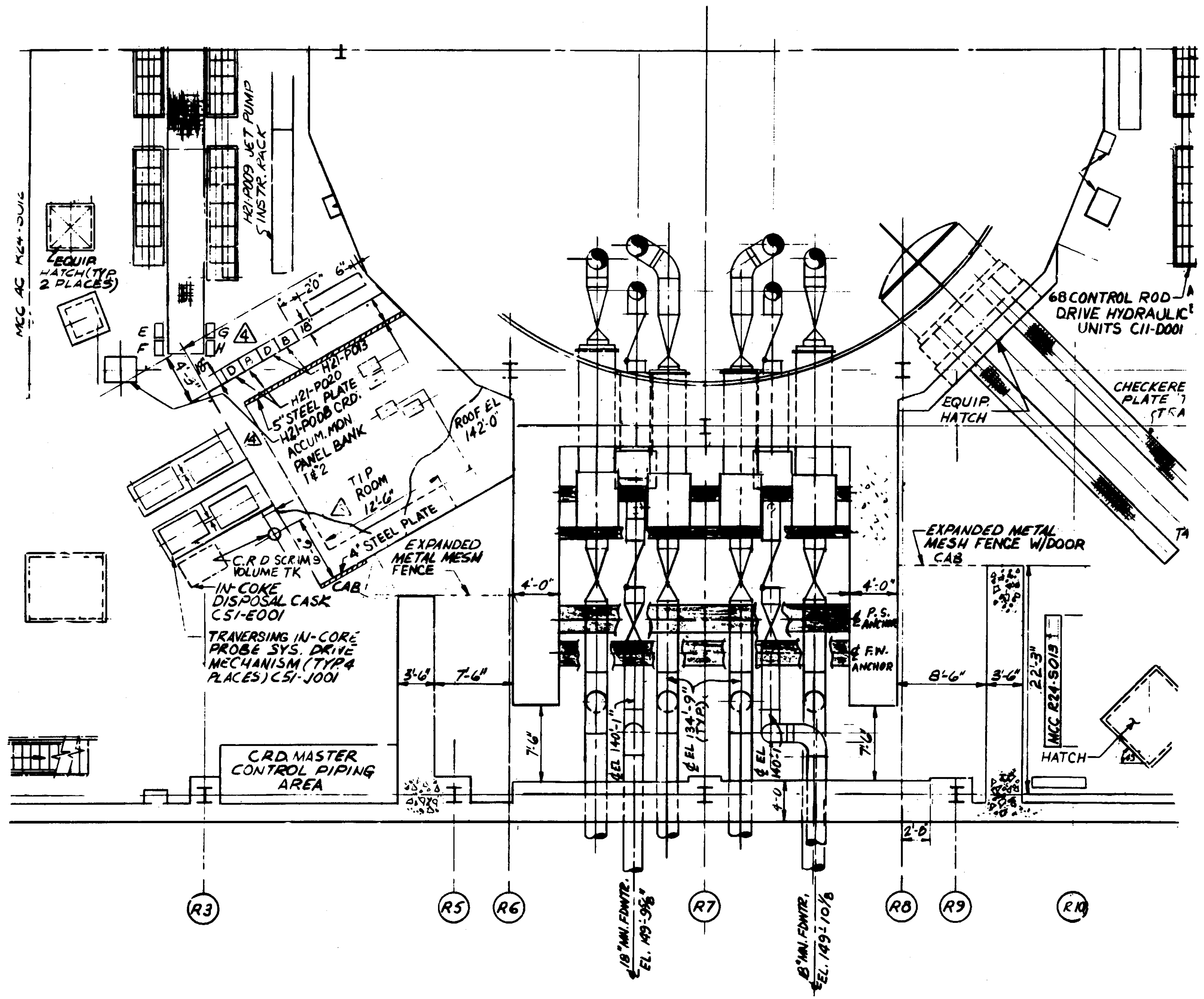
Description of Equipment Required	High-Energy Line Break[a] Main Steam	Feed-water	HPCI Steam	RCIC Steam	RWC
Reactor protection system (scram signals)	x	x	x	x	x[b]
Reactor vessel and primary containment isolation control system	x	x	x	x	x[c]
MCR environmental system	x	x	x	x	x[d]
Pressure relief equipment					
Relief valves	x	x	x	x	x[e]
Pressure suppression pool (passive)	x	x	x	x	x
Flow restrictors (passive)	x[f]				
Core cooling preferences[g]					
Incident detection circuitry (RPV low level only)	x	x	x	x	x[h]
One of the following combinations required for core cooling and makeup:					
HPCI or RCIC	x	x			x
One LPCI or core spray loop			x	x	
RHR shutdown cooling mode	x	x	x	x	x[i]
RHR suppression pool cooling mode (one loop)	x	x	x	x	x
RHRSW to one RHR heat exchanger	x	x	x	x	x[i]

TABLE N.5-2 (SHEET 2 OF 3)

Description of Equipment Required	High-Energy Line Break[a] Main Steam	Feed-water	HPCI Steam	RCIC Steam	RWC
Electrical power systems					
Emergency ac power (2 or 3 diesel generators)	x	x	x	x	x
Onsite dc power (125/250 V-dc power system)	x	x	x	x	x
4160-V emergency buses (2 of 3 emergency buses)	x	x	x	x	x
600-V emergency buses (1 of 2 buses)	x	x	x	x	x
MCCs for above equipment	x	x	x	x	x
Service water requirements[j]					
Diesel generator jacket cooling	x	x	x	x	x
RHR pump cooling	x	x	x	x	x
RHR room cooling	x	x	x	x	x
HPCI room cooling	x	x		x	x
RCIC room cooling	x	x	x		x
Instrumentation for post-accident monitoring					
Reactor pressure indication	x	x	x	x	x
Reactor water level indication	x	x	x	x	x
Suppression pool temperature indication	x	x	x	x	x
Suppression pool water level indication	x	x	x	x	x

TABLE N.5-2 (SHEET 3 OF 3)

a. An x indicates a requirement and/or preference for that particular line break.
b. Scram trip signals, settings, and operability requirements are provided in the Technical Specifications. A detailed discussion of these may be found in section 7.2 of the FSAR. Generally, low reactor water level will initiate a scram for most high-energy line breaks.
c. Instrumentation required to initiate reactor vessel and primary containment isolation with corresponding trip settings is listed in Technical Specifications table 3.3.6.1-1. A detailed discussion of these is given in section 7.3 of the FSAR. Instrumentation required to isolate core cooling systems is listed in the Technical Specifications.
d. This system, as described in section 10.17, assures continued habitability of the control room following any high-energy line break.
e. There are 11 relief valves as described in section 4.4 of the FSAR. These valves are located inside the primary containment.
f. Flow restrictors for the main steam lines, as described in section 4.5 of the FSAR, are required to reduce the blowdown from an MSLB. These restrictors are located inside the primary containment.
g. Due to the flexibility of design with respect to ECCS, reactor coolant injection systems, and the various modes of the RHR system, it is more appropriate to list equipment preferred for use in plant shutdown. There are several automatic actions that serve to back up the preferred action, e.g., HPCI and RCIC perform similar functions. There are also options available to the operator such as utilizing both RHR loops, if available. These systems and functions are described in chapters 4 and 6 of the FSAR.
h. Instrumentation and trip settings required for initiation of core cooling systems are specified in the Technical Specifications. Detailed descriptions of core cooling systems are found in chapter 6 of the FSAR.
i. See discussion in section N.5, item 2.
j. Room or pump cooling requirements are per Technical Requirements Manual and the Technical Specifications definition of OPERABILITY.



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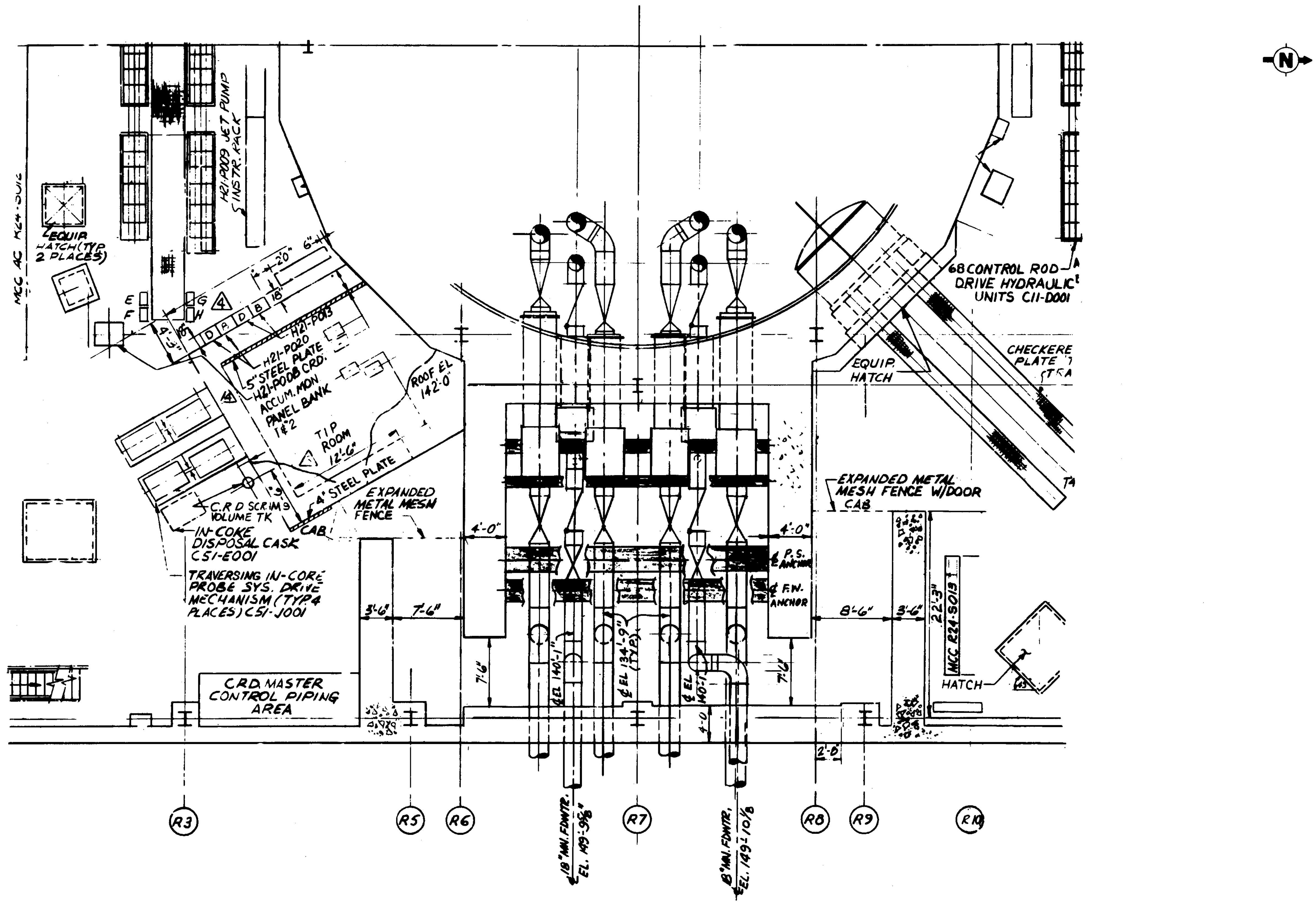
UNIT 1

MAIN STEAM AND FEEDWATER LINES,
MAIN STEAM PIPE CHASE, REACTOR BUILDING,
ELEVATION VIEW

FIGURE N.5-1



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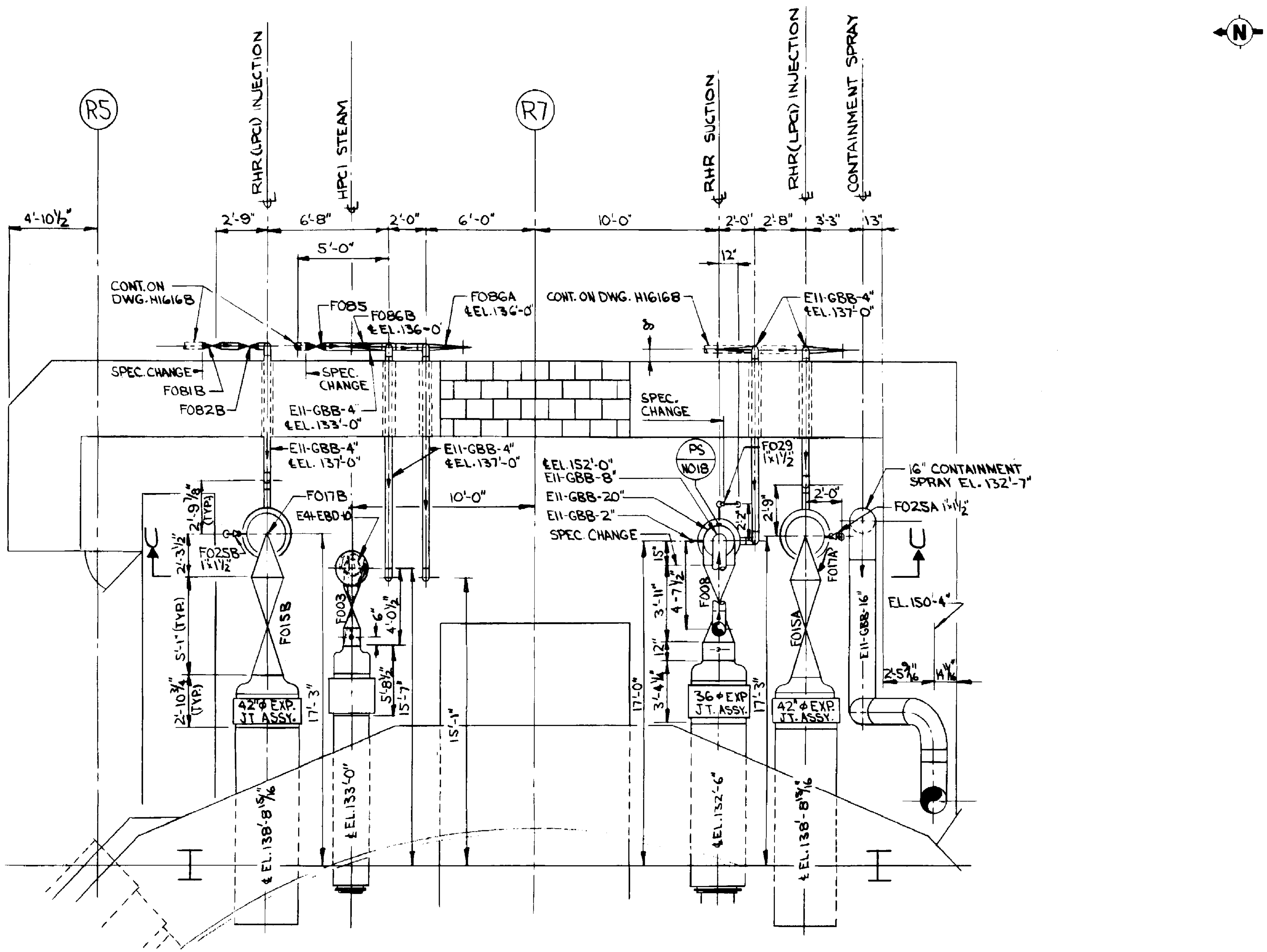
MAIN STEAM AND FEEDWATER LINES,
MAIN STEAM PIPE CHASE, REACTOR BUILDING,
PLAN VIEW

FIGURE N.5-2



ACAD 10n0503

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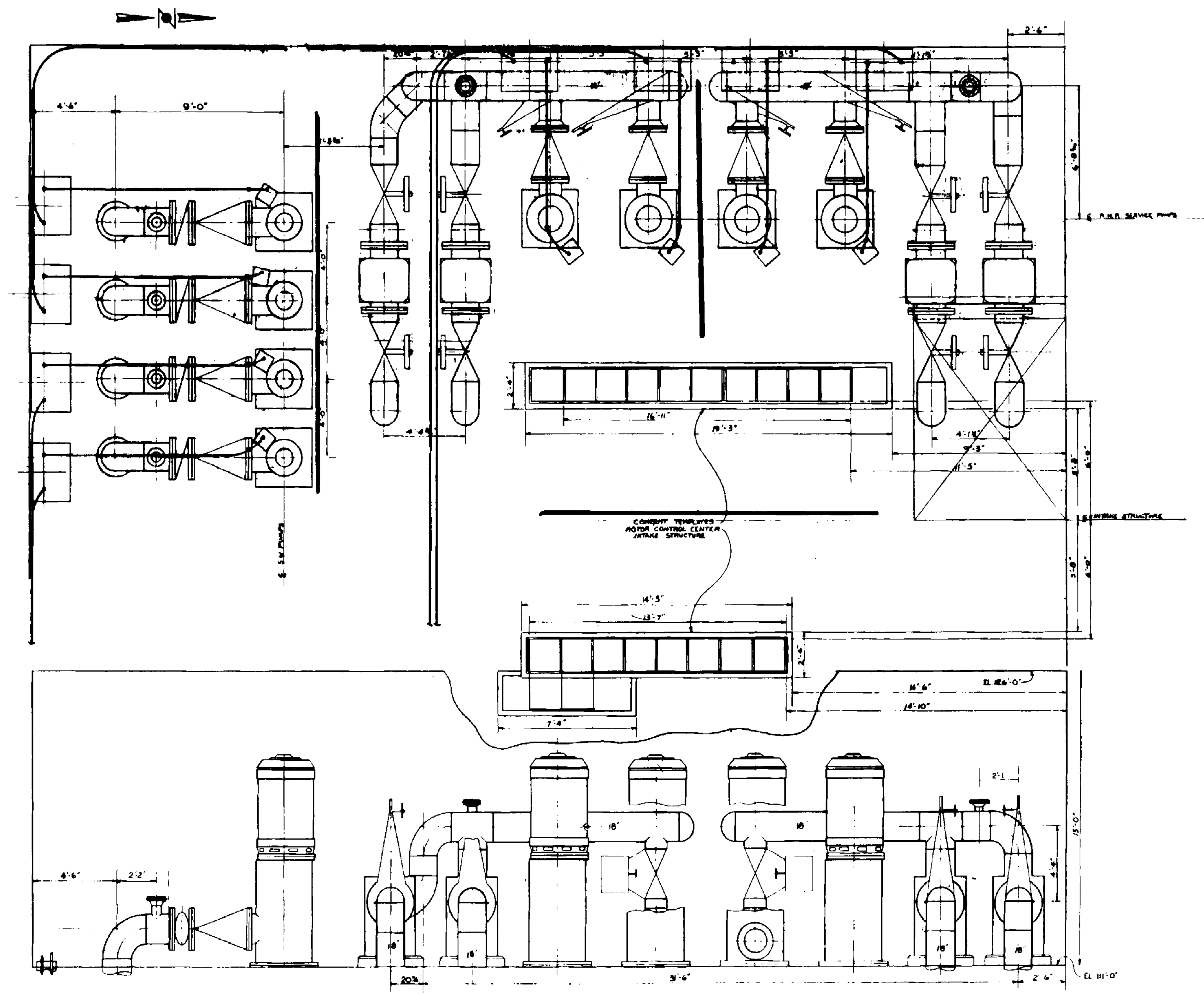
HPCI STEAM AND RHR LINES PIPE
PENETRATION ROOM REACTOR BUILDING
el 130 ft PLAN VIEW

FIGURE N.5-3



ACAD 10n0508

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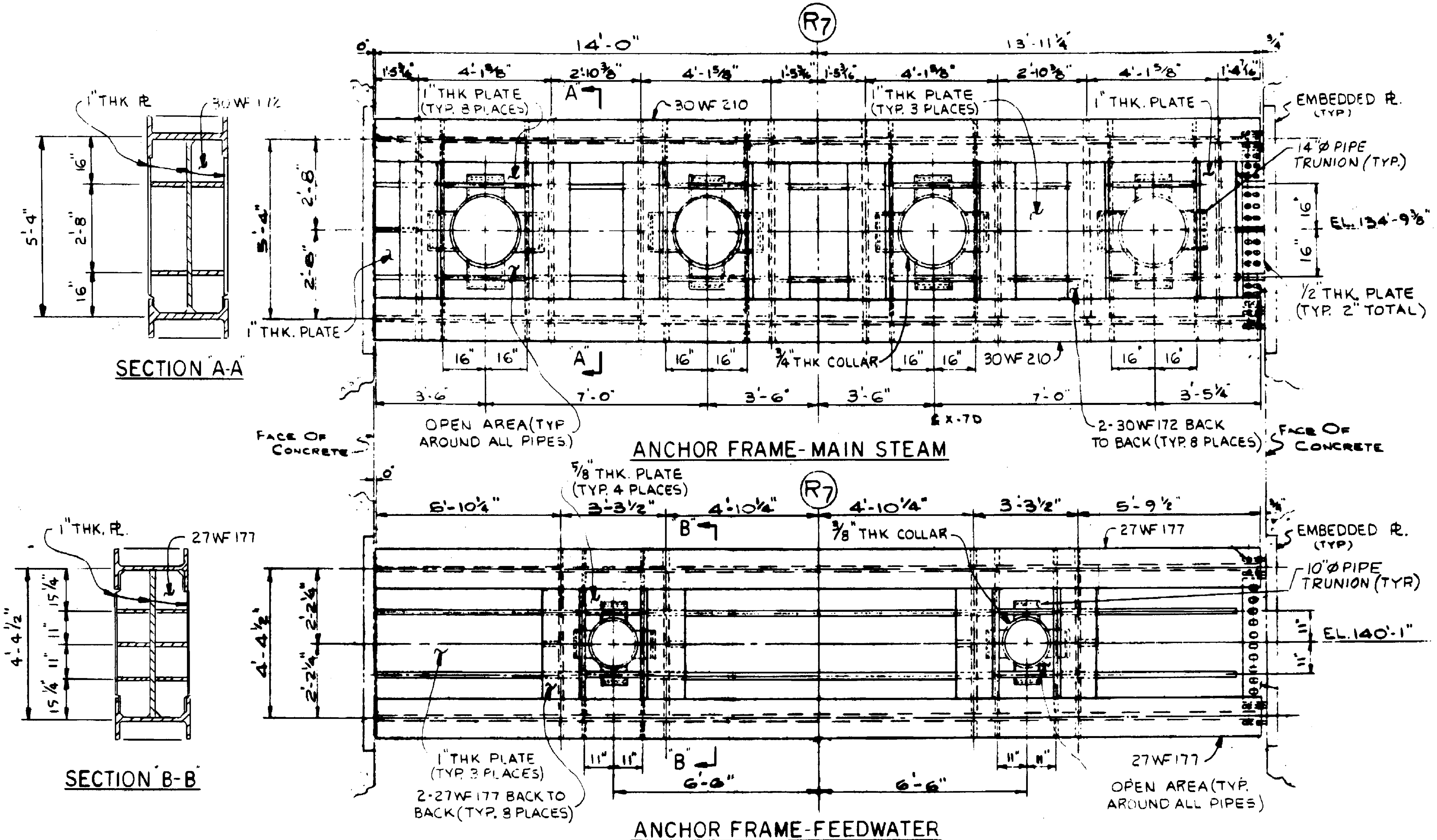
RHR AND PSW PIPING IN INTAKE STRUCTURE

FIGURE N.5-8



ACAD 10n0509

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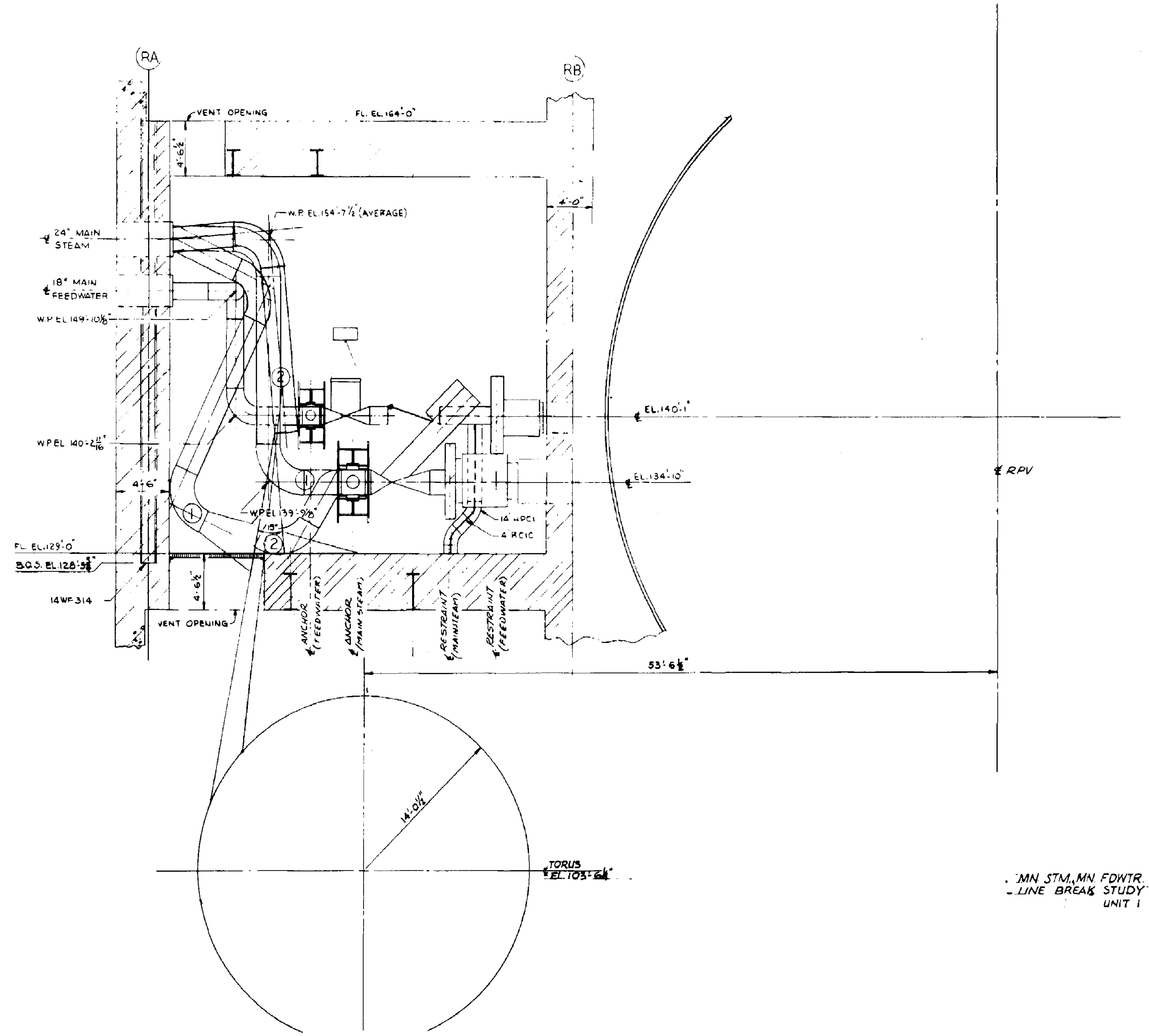
MAIN STEAM AND FEEDEATER ANCHOR FRAME DETAILS, MAIN STEAM PIPE CHASE

FIGURE N.5-9



ACAD 10n0510

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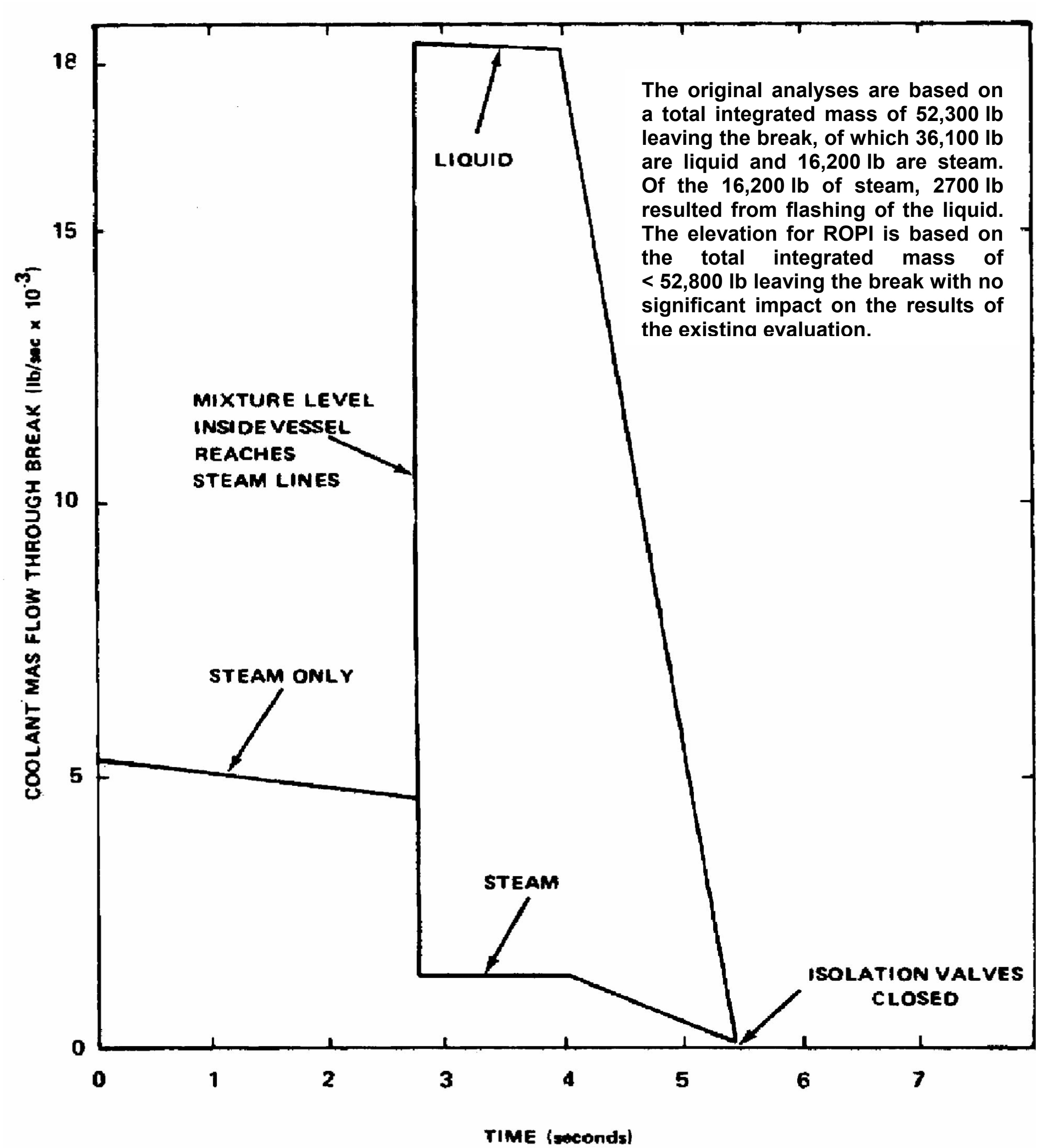
JET IMPINGEMENT EVALUATION, MSLB IN MAIN STEAM PIPE CHASE, REACTOR BUILDING

FIGURE N.5-10



ACAD 10n0511

REV 22 9/04

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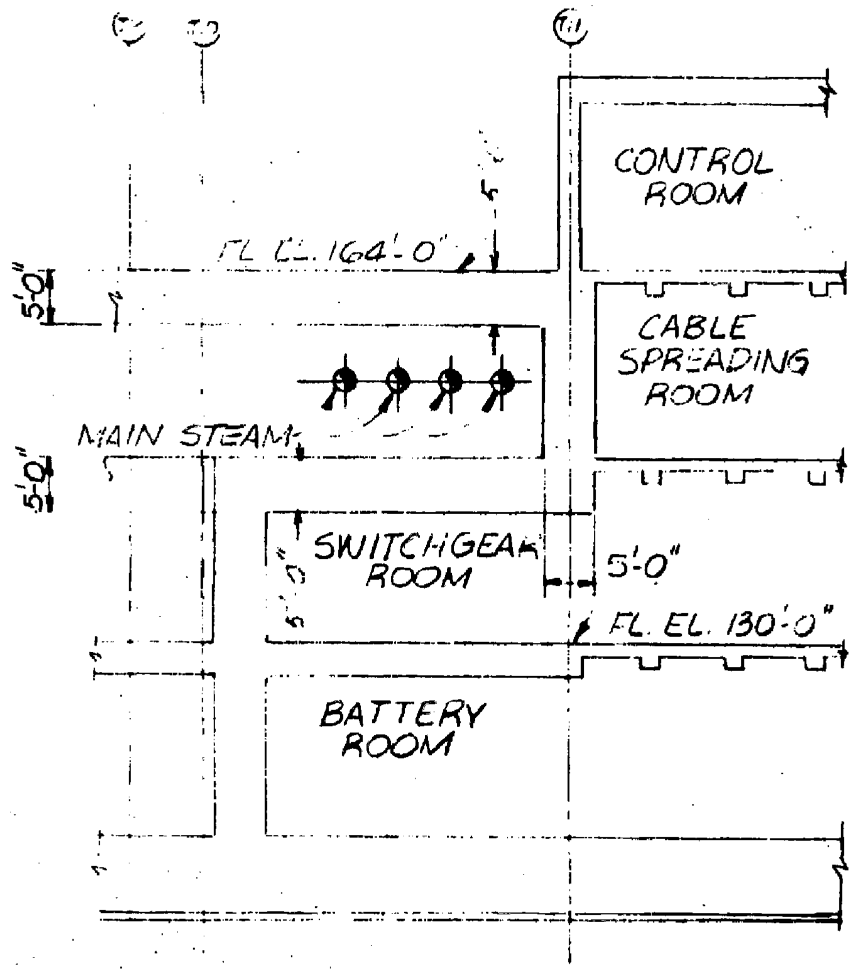
MSLB, MASS OF COOLANT LOSS THROUGH BREAK WITH 5-s MSIV CLOSING TIME

FIGURE N.5-11



ACAD 10n0512

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LOCATION OF MCR WITH RESPECT TO MAIN STEAM LINES, VIEW LOOKING EAST

FIGURE N.5-12

N.6 SUMMARY OF PROPOSED PLANT MODIFICATIONS

Although discussed by system in section N.5, this section provides a summary of plant modifications designed to mitigate the effects of postulated high-energy and moderate-energy line failures outside the primary containment.

N.6.1 MODIFICATIONS AS A RESULT OF PRESSURE TEMPERATURE ANALYSES

As a result of detailed pressure temperature transient analyses, some compartments were found to be overpressurized. For these compartments, additional vent area was provided in the form of clear (unobstructed) vent openings, grated vent openings, or blowout panels. The selection of the locations for such vents was based on a combination of factors such as efficiency in solving the pressurization problem, evaluation with respect to structural loadings and bearings, effect on plant personnel accessibility, effect on construction man-hours and difficulty, as well as economic considerations. Locations where such modifications have been provided are summarized as follows:

A. For a main steam line break (MSLB) in the pipe chase, reactor building

   1. A blowout panel (75 ft^2) has been provided between pipe chase and turbine building, above el 147 ft. This vent area is sketched in figure N.6-1, sheet 2.

   2. Open vents (total 200 ft^2) have been provided from pipe chase to heating, ventilation, and air-conditioning (HVAC) room directly above at el 164 ft. These vents are sketched in figure N.6-1, sheet 1.

   3. Blowout panels (total 269 ft^2) have been provided between HVAC room above pipe chase and turbine building, above el 164 ft. These vents are sketched in figure N.6-1, sheet 3.

   4. Grated vent openings (total 200 ft^2) have been provided in the floor of the pipe chase at el 129 ft. These vents are sketched in figures N.6-2 (plan view) and N.5-1 (section view).

B. For a high-pressure coolant injection (HPCI) steam line break in the pipe penetration room, reactor building:

   1. The hatches on the roof for this room have been converted to grating. This provides about 90 ft^2 of obstructed vent area, and 82 ft^2 of vent area, was used in the analysis (15% of area was assumed to be grating.) The hatch arrangement for the roof of this room is depicted in figure N.6-3.

   2. The block wall opposite the containment personnel lock is reinforced with removable steel plates to enable it to take the internal pressure without collapsing.

3. Temperature sensors have been provided to enable detection of a failure in the HPCI steam line that would deliver less than 300% blowdown flow.

C. For a HPCI steam line break in the torus room, reactor building basement

1. Above the reactor core isolation cooling (RCIC) corner room, a 42-ft^2 hatch was changed to grating to allow the corner room to vent to the large el 130 ft floor compartment. The hatch is depicted in figure N.6-4.

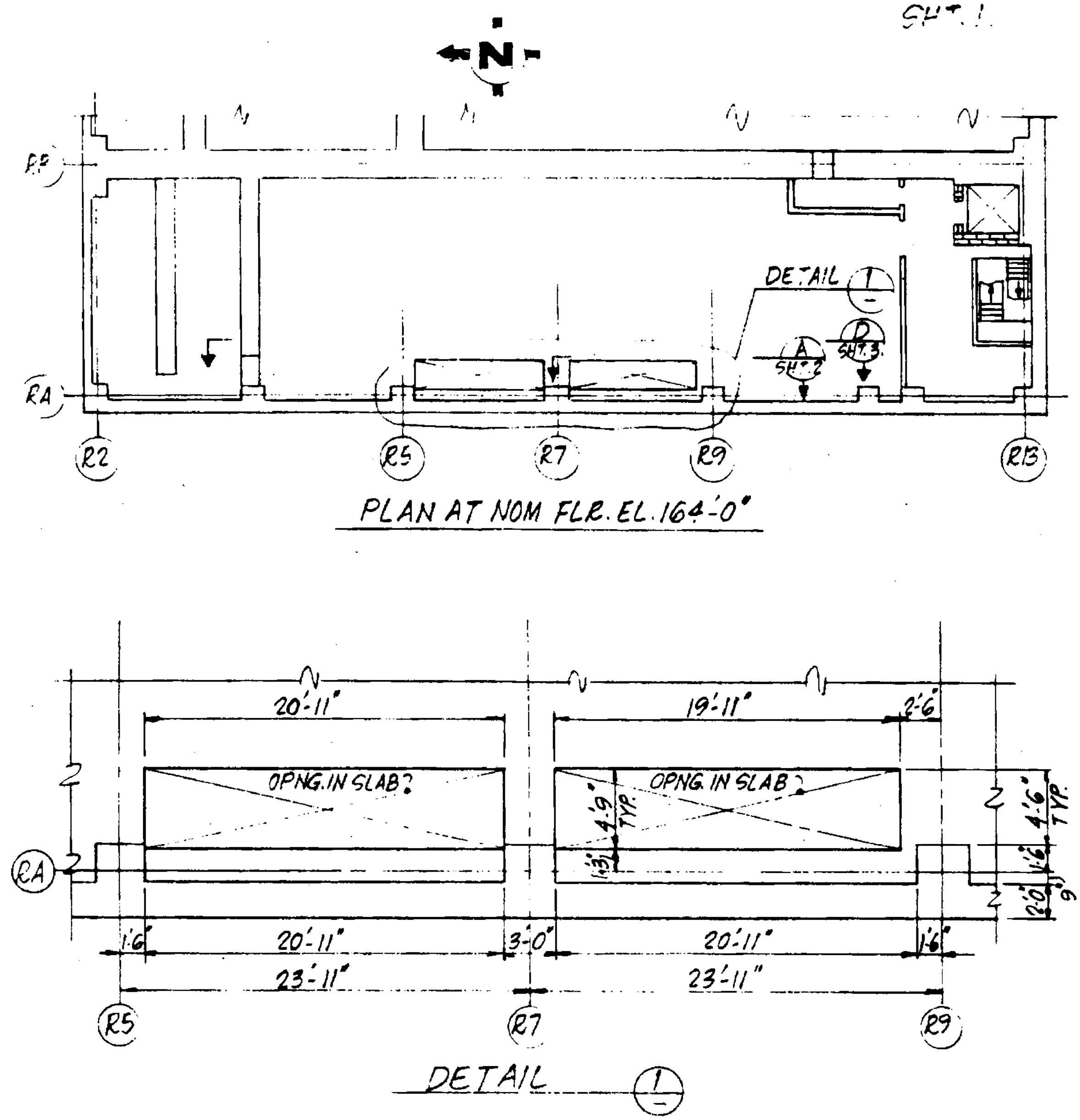
2. All vent areas around piping and ducting penetrations leading into the residual heat removal (RHR) (east) corner rooms were sealed to preclude the adverse environment from entering these rooms and affecting the operation of the RHR system.

3. Grated vent openings (total 200 ft^2) are provided in the floor of the main steam pipe chase at el 129 ft. These vents are sketched in figures N.6-2 (plan view) and N.5-1 (section view).

N.6.2 BARRIERS PROVIDED TO PROTECT AGAINST JET IMPINGEMENT

Various locations have been determined to have potential jet impingement problems. Where identified, it was conservatively decided that barriers would be provided to protect the targets. These locations are summarized as follows:

Line Failure	Target Protected	Location
Reactor water cleanup line crack floor el 130 ft	Cable tray	Reactor building
Control rod drive return line floor el 130 ft	Cable tray	Reactor building
Auxiliary steam line crack	Motor control centers	Reactor building floor el 130 ft
Auxiliary steam line crack	Flex cable for HPCI steam line isolation valve operator	Pipe penetration room, floor el 130 ft of reactor building
Residual heat removal service water (RHRSW) water line cracks	RHRSW motors and associated equipment	River intake structure



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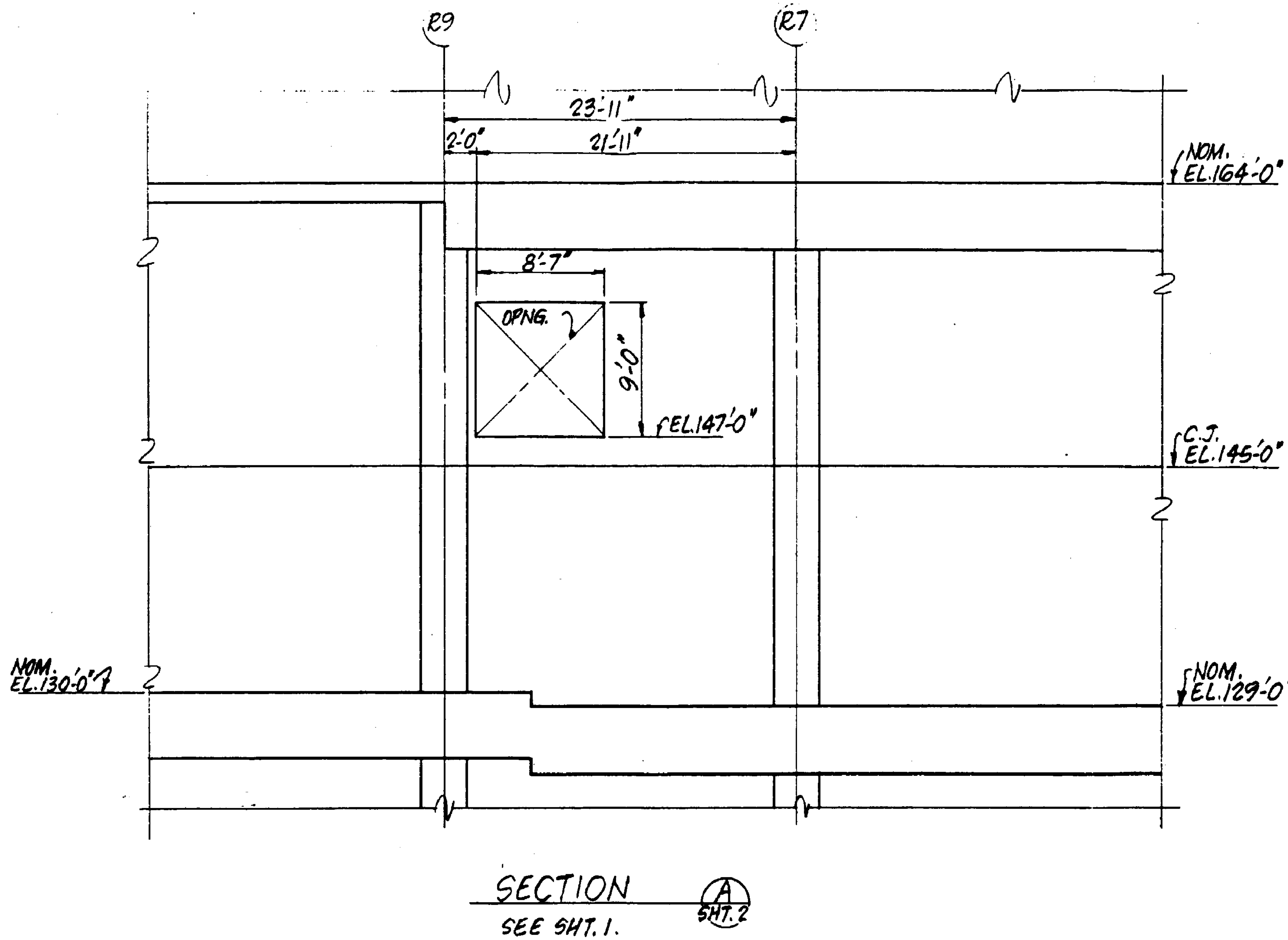
VENT AREA ADDITION TO HVAC ROOM, REACTOR BUILDING el 164 ft FROM MAIN STEAM PIPE CHASE FOR MSLB

FIGURE N.6-1 (SHEET 1 OF 3)



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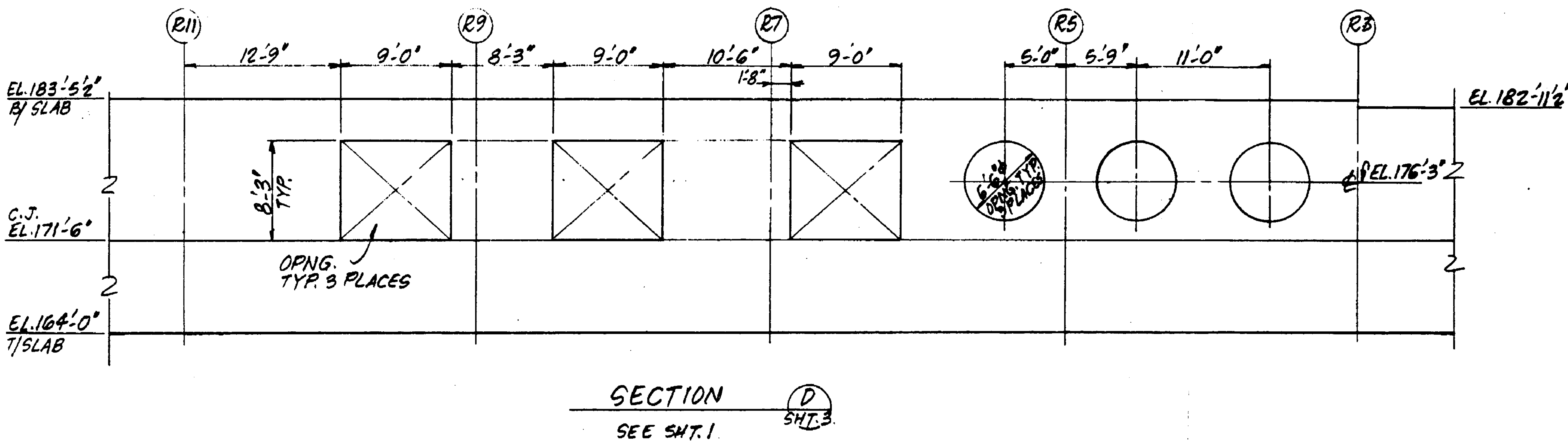
VENT AREA ADDITION TO TURBINE BUILDING FROM MAIN STEAM PIPE CHASE FOR MSLB

FIGURE N.6-1 (SHEET 2 OF 3)



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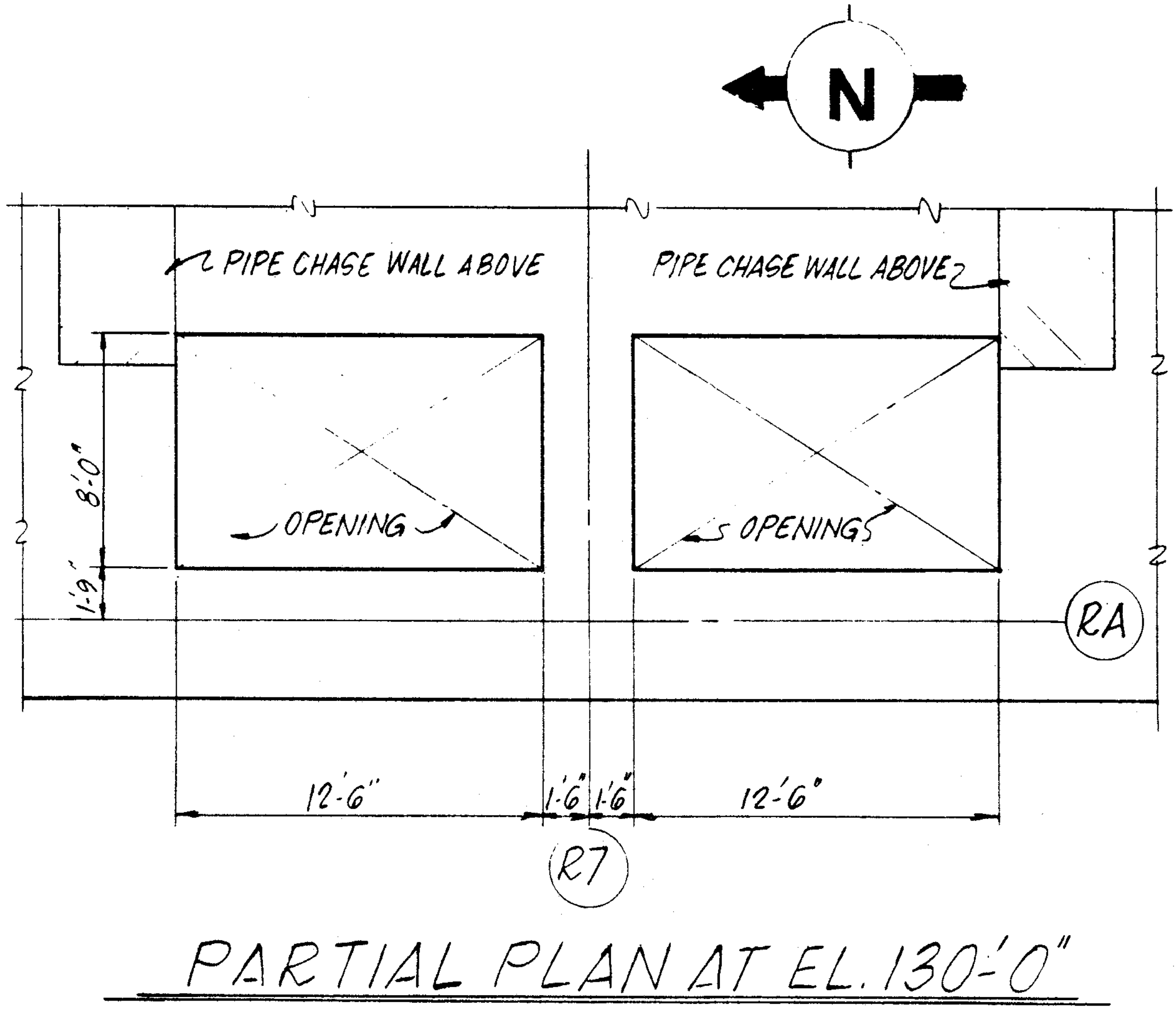
VENT AREA ADDITION TO TURBINE BUILDING FROM HVAC ROOM AT el 164 ft REACTOR BUILDING FOR MSLB

FIGURE N.6-1 (SHEET 3 OF 3)



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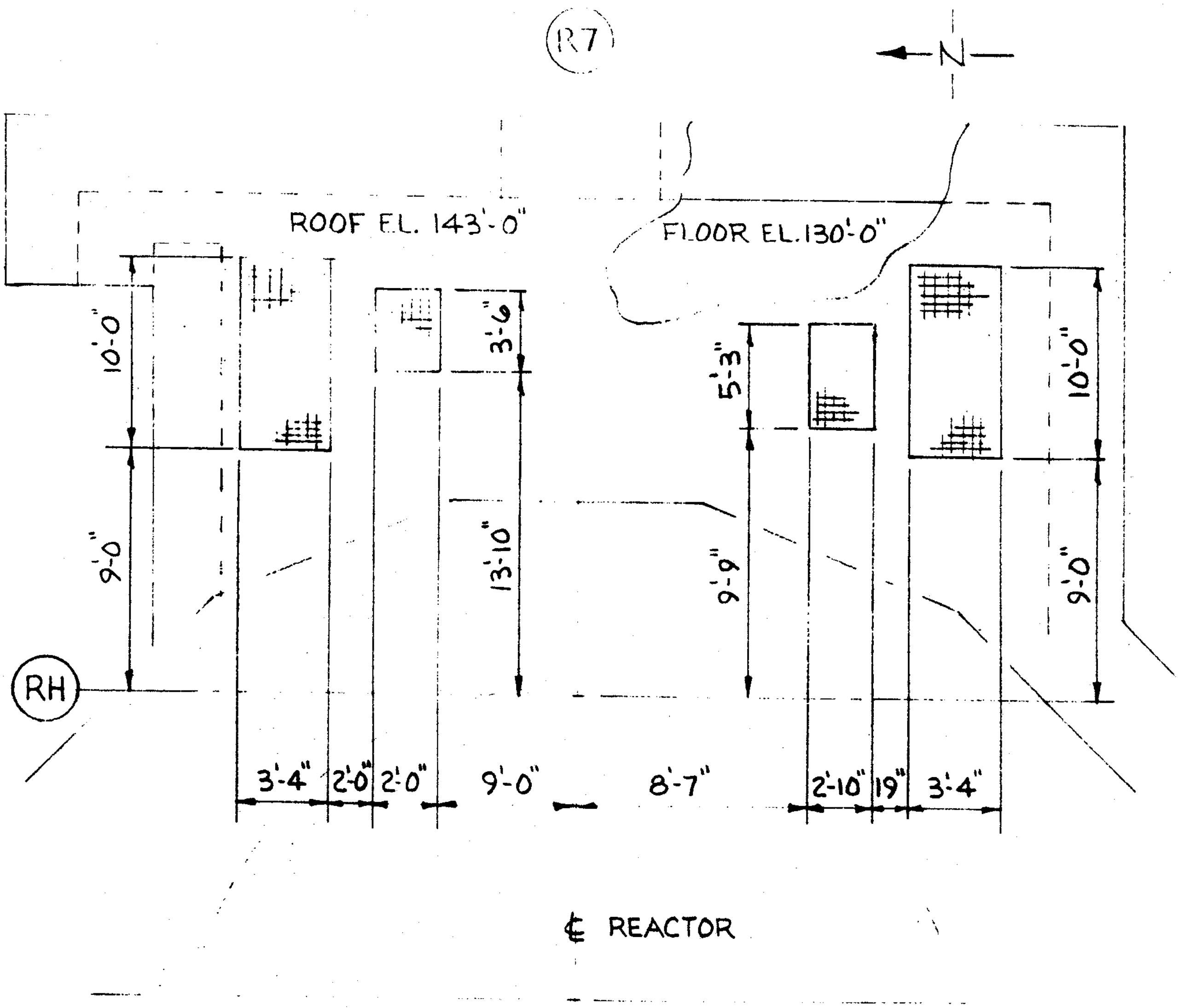
MAIN STEAM PIPE CHASE FLOOR
el 129 ft ABOVE TORUS CHAMBER ROOM

FIGURE N.6-2



PLAN
PIPING PENETRATION ROOM
NO SCALE

REV 19 7/01

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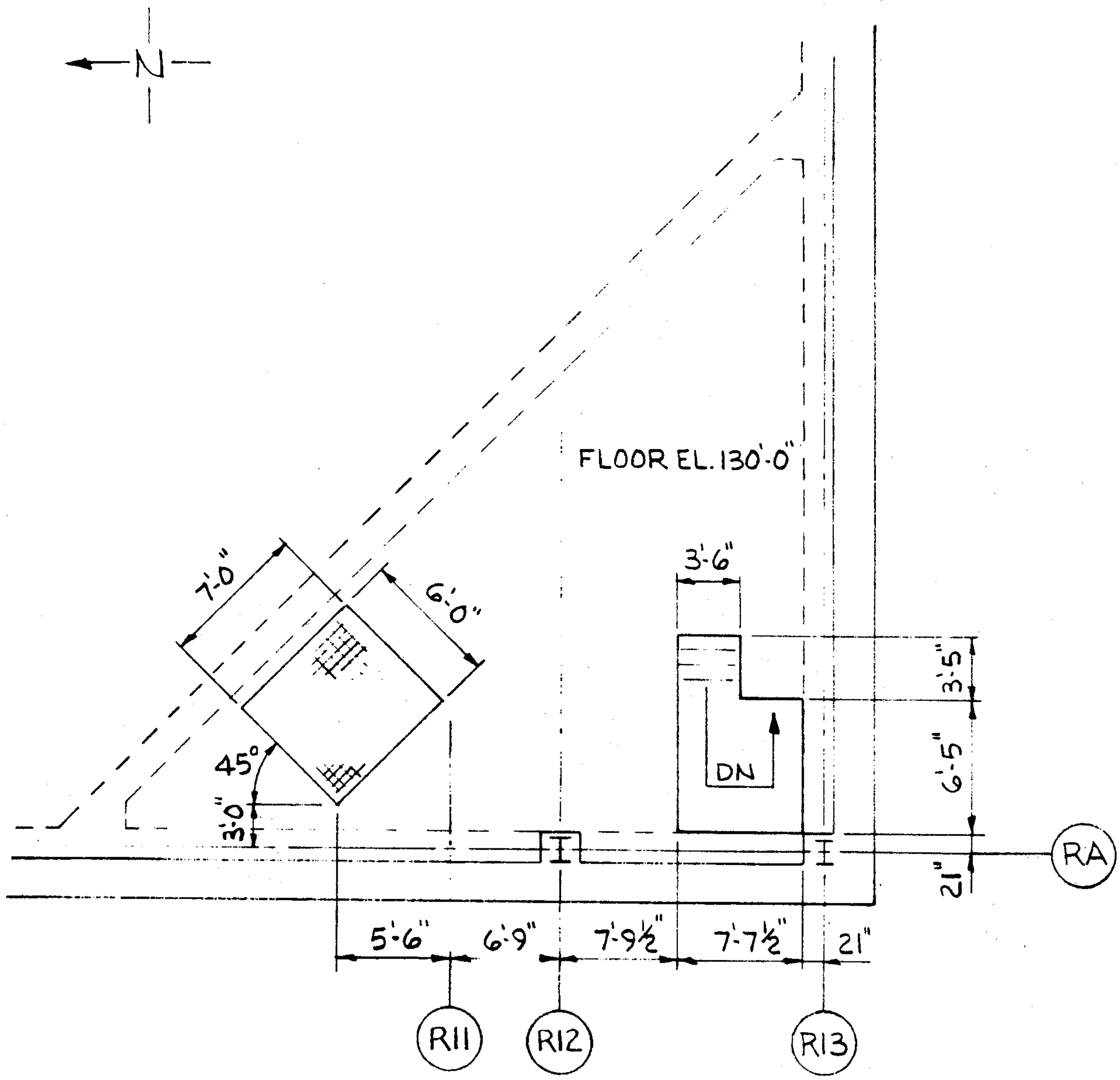
UNIT 1

PIPE PENETRATION ROOM,
REACTOR BUILDING FLOOR el 130 ft,
ROOF HATCH ARRANGEMENT

FIGURE N.6-3



PLAN
S.W. CORNER
NO SCALE

REV 19 7/01

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UNIT 1

REACTOR BUILDING FLOOR el 130 ft
ABOVE RCIC (SW) CORNER ROOM

FIGURE N.6-4

N.7 CONCLUSIONS

The analysis of postulated high-energy and moderate-energy line failures outside the primary containment as previously discussed in detail has been completed. The following conclusions are drawn:

A. With the plant modifications for additional vent area, no structure or structural element will fail due to pressurization or direct effects from a failure. The resultant environmental atmosphere in any room containing equipment required for safe shutdown of the reactor is such that the ability of the equipment to perform its required function is not precluded.

B. The physical capability for safe shutdown of the reactor is maintained for any postulated failure of high-energy or moderate-energy lines. The ability to safely shut down the reactor also includes the assurance that radioactive releases do not exceed 10 CFR 100 values, mechanical and thermal limits for catastrophic failure of the fuel barrier are not exceeded, nuclear and containment system stresses allowed for accidents by applicable codes are not exceeded, and 10 CFR 50, Appendix A, limits for control room personnel are not exceeded.

Although the Edwin I. Hatch Nuclear Plant-Unit 1 is designed and constructed to quality standards that makes the failure of high-energy or moderate-energy lines highly unlikely, the analysis presented in this report indicates that with the plant modifications, the plant can withstand the effects of the postulated failures.

APPENDIX R

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM

R.1 FLUENCE AT INNER WALL OF THE REACTOR PRESSURE VESSEL

Following the analysis of iron, nickel, and copper flux dosimeters irradiated in a standard General Electric pressure vessel capsule holder at HNP-1 from October 19, 1974, to September 29, 1984, the neutron fluence at the capsule (located on the inner surface of the vessel) was calculated to be 2.4×10^{17} n/cm^2 for neutrons having energies > 1 MeV. For the capsule irradiated from October 1974 to March 1996, the neutron fluence was calculated to be 4.6×10^{17} n/cm^2.

Computer analysis was done to analytically predict the flux distribution in order to determine the maximum fluence at the 1/4T depth. Based upon the analysis, using the 1996 flux dosimeter results, the maximum 1/4T fluence at 32 effective full-power years (EFPYs) (40-year plant life times 0.8 capacity factor) is 1.3×10^{18} n/cm^2.

HNP-2-FSAR subsection 5.2.4 discusses the predicted 1/4T fluence for various EFPYs out to the end of the operating license (EOL).

The methodology used by SNC/Hatch to calculate neutron fluence complies with the requirements of Regulatory Guide 1.190.

R.2 EFFECTIVE FULL-POWER YEARS OF SURVEILLANCE SPECIMEN REMOVAL

The first surveillance capsule was removed following the operating cycle that ended on September 29, 1984 with 5.7 accumulated effective full power years (EFPY). The second surveillance capsule was removed following the operating cycle ending on March 23, 1996, with an accumulated EFPY of 14.3.

The third surveillance specimen is scheduled for removal following the 27th operating cycle in 2016 with a projected EFPY of 32.3.

REFERENCES

1. "Determination of Fast Neutron Flux Density and Fluence, Hatch 1 Power Station", GE Report No. 266-7801-02, March 1978 transmitted via General Electric letter G-GPC-8-42.

2. "Edwin I. Hatch Nuclear Power Plant, Unit 1, Reactor Pressure Vessel Surveillance Materials Testing and Fracture Toughness Analysis", General Electric Report NEDC-30997, October 1985.

3. "Plant Hatch Unit 1 Surveillance Materials Testing and Analysis", General Electric Report GE-NE-B1100691-01R1, March 1997.

4. "Edwin I. Hatch Unit 1 Fabrication of New Surveillance Capsule with Reconstituted Charpy Specimens", GE-NE-B1100691-02, General Electric, September 1998.

R.3 REACTOR PRESSURE VESSEL (RPV) SUPPLIER AND SPECIFICATIONS

The Hatch 1 reactor pressure vessel was purchased from and fabricated by Combustion Engineering Inc., Chattanooga, Tennessee (purchase order No. H0425). The reactor vessel is designed and constructed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code - Section III, 1965 Edition and Addenda through Winter 1966 (Case 1339-2).

R.4 VESSEL BELTLINE MATERIAL

R.4.1 PLATE AND WELD LOCATION

Materials in the reactor pressure vessel beltline region (as defined in 10 Code of Federal Regulations (CFR) 50, Appendix G, Section II.F) are identified below as shown in figure R.4-1.

R.4.2 PLATES/FORGING AND WELDS

All shell plate material SA-533 Grade B, Class 1; Combustion Engineering Specification P3F12(b), September 6, 1966, is provided by Lukens Steel Company, Coatesville, Pennsylvania. The submerged arc process was used for all welds shown and was performed by Combustion Engineering.

R.4.2.1 Lower Shell Course

A. Plates (3) - 305-04

PC No.	Code No.	Heat No.	Slab No.
305-04A	G4805-1	C4112	1
305-04B	G4805-2	C4112	2
305-04C	G4805-3	C4149	1

B. Vertical Weld Seams 1-307 A, B, C

- Coated electrodes - filler metal type 8018

  Wire heat number: Information was not available.

  Lot number: EAGH

  Combustion Engineering weld procedure specification: MA-33B(4)

  Weld procedure number: TSAA-2(A)0

- Flux electrode combinations - filler metal type B-4 mod

  Wire heat number: 13253

  Flux type: Linde 1092

  Lot number: 3791

Material: Not recorded (N/R)

Supplier: Adcom Metals Co., Atlanta, Georgia

Combustion Engineering weld procedure specification: SAA-33-L(1)

Weld procedure number: TSAA-2A0

R.4.2.2 Lower Intermediate Shell Course

A. Plates (1) - 305-02; (2)-305-03

PC No.	Code No.	Heat No.	Slab No.
305-02D	G4803-7	C4337	1
305-03A	G4804-1	C3985	2
305-03B	G4804-2	C4114	2

B. Vertical Weld Seams 1-308 A, B, C

1. Coated electrodes - filler metal type E8018

   Wire heat number: Information was not available.

   Lot number: LACH

   Combustion Engineering weld procedure specification: MA-11A(6)

   Weld procedure number: TSAA-2A-0

2. Flux electrode combinations - filler metal type B-4 mod

   Wire heat numbers: 1P2809 and 1P2815

   Flux type: Linde 1092

   Lot number: 3854

   Material: M M M

   Combustion Engineering weld procedure specification: SAA-33-H(3)

   Weld procedure number: TSAA-2A-0

R.4.2.3 <u>Girth Weld Seam 1- 313</u>

A. Coated Electrodes - filler metal type 8018

Wire heat number: Information was not available.

Lot numbers: ICJJ, IOBJ

Combustion Engineering weld procedure specification: MA-33-B(4)

Weld procedure number: SAA-MA-502-0

B. Flux Electrode Combinations - filler metal type B-4 mod

Wire heat numbers: 90099 and 33A277

Flux type: Linde 0091

Lot number: 3977

33A277 material: Hi mang moly

Supplier: The Reid Avery Company, Baltimore, Dundalk, Maryland 90099 supplied by American Chain and Cable Company

Combustion Engineering weld procedure specification: SAA-11-S(2)

Weld procedure number: SAA-MA-502-0

R.4.3 HEAT TREATMENT

R.4.3.1 <u>Plates and Test Specimens</u>

All plate test specimens were heated 1550 to 1650°F, held 4-h maximum, and program cooled per Combustion Engineering cooling rate; then tempered 1200 to 1250°F, held 4-h maximum, and air cooled.

Test specimens were stress relieved 1125 to 1175°F, held 40-h, and furnace cooled at a rate of 4-h minimum to 600°F.

R.4.3.2 Post-Weld Heat Treatment

Combustion Engineering furnace logs for the Hatch 1 pressure vessel report the following time spans:

Vessel Description	Hours to Go from Room Temperature to 1150 ± 25°F	Hours Held at 1150 ± 25°F	Hours to Cooldown to 600°F
Lower shell assembly	11	7	15
Lower shell	13	1	12
Lower vessel assembly repair	12	7	12
Upper to lower shell assembly	14	7 1/2	8
Upper to lower shell girth	18 1/2	2	9

R.4.4 CHEMICAL ANALYSES

At the time of construction for these pressure vessels, the only requirements for chemical composition were those contained in the American Society of Testing Materials material specifications (A533 Grade B for plate; and A233, A298, A316, or A371 for weld electrodes and rods). The elements reported in these specifications include C, Mn, P, S, Si, Mo, and Ni, but not Cu. By tracing the heat numbers for the beltline plates back to Lukens Steel (the supplier), the copper contents for the plate material were obtained. The ladle analysis for present Cu is measured and retained by the supplier even if it is not required by the purchase specification. For the surveillance plate material, samples were taken from the irradiated base Charpy specimens and tested for Mn, P, Ni, Mo, Cr, Si, and Cu.

Characteristics of the as-deposited weld metal copper contents could only be obtained by chemical analysis of samples representing the actual pressure vessel weld seams. This analysis was performed by Plasma Emission Spectrometry (PES) on the weld material from two HAZ surveillance Charpy specimens.

The PES testing evaluated weight percent of Mn, Ni, Mo, Si, and Cu. The surveillance specimen weld was made by the same processes as longitudinal beltline weld 1-308, but specific identification of the wire heat and flux lot numbers was not obtained. A test weld was made and evaluated by Combustion Engineering using one of the wire heats (IP2815) from longitudinal weld 1-308, but using a different flux. The chemistry of the test weld, along with the PES results of the surveillance weld, are used to characterize the chemistry of the longitudinal beltline welds. For the surveillance weld material, samples were taken from the irradiated weld Charpy specimens and tested for Mn, P, Ni, Mo, Si, and Cu.

The chemical analyses for vessel beltline plate materials are as follows:

				(%)				
Description	C	Mn	P	S	Cu	Si	Ni	Mo
Plate								
Lower shell course								
Plate numbers								
305-04A	0.21	1.38	0.011	0.014	0.13	0.27	0.64	0.57
305-04B	0.24	1.38	0.011	0.014	0.13	0.27	0.64	0.57
305-04C	0.22	1.28	0.009	0.012	0.14	0.20	0.57	0.54
Lower intermediate shell course								
305-02D	0.24	1.36	0.011	0.013	0.17	0.27	0.62	0.57
305-03A	0.22	1.40	0.015	0.015	0.13	0.27	0.58	0.53
305-03B	0.24	1.43	0.010	0.013	0.13	0.28	0.70	0.54
Surveillance Plate (heat C4114-2)								
305-0413	NA	1.54	0.013	NA	0.12	0.23	0.70	0.57
Weld								
Flux electrode filler type B B-4 mod								
Heat no./ Flux type/ Lot no.								
13253/1092/ 3791	N/R	N/R	N/R	N/R	0.27	N/R	0.74	N/R
1P2809/1092/ 3854	N/R	N/R	N/R	N/R	0.28	N/R	0.76	N/R

				(%)				
Description	C	Mn	P	S	Cu	Si	Ni	Mo
1P2815/1092/ 3854	0.13	1.32	0.013	0.009	0.28	0.24	0.76	0.52
90099/0091/ 3977	0.15	1.12	0.022	0.012	0.17	0.23	1.00	0.49
33A277/0091/ 3977	0.16	1.09	0.017	0.012	0.23	0.18	1.00	0.49
CE Test weld								
IP2815/1092/ 3869	0.11	1.38	0.010	0.009	0.27	0.20	0.72	0.51
Surveillance Weld 1-308	N/R	1.4	N/R	N/R	0.28	0.19	0.76	0.50[a]
	N/R	1.51	0.011	N/R	0.30	0.22	0.82	0.55[b]
Coated electrode filler type 8018								
Lot no./mix								
EAGH/6981	0.078	1.06	0.013	0.009	N/R	0.43	0.97	0.24
LACH/6981	0.08	1.03	0.009	0.011	N/R	0.41	0.90	0.24
IOBJ/7783	0.092	1.10	0.010	0.012	0.02	0.45	0.97	0.27
ICJJ/7783	0.097	0.99	0.011	0.013	0.03	0.42	0.99	0.24

a. Average of two irradiated Charpy specimens in 1985.
b. Average of five irradiated Charpy specimens in 1985 and 1997.

R.4.5 TENSILE PROPERTIES (UNIRRADIATED)

Heat No.	Slab No.	Yield Strength (ksi)	Ultimate Strength (ksi)	Test No.
Plates				
Lower shell course				
C4112	1	68.7/69.5	91.5/91.7	HDTA/B
C4112	2	69.3/69.2	90.4/90.5	PHTA/B
C4149	1	65.8/65.8	88.9/88.8	PITA/B
Lower intermediate shell course				
C4337	1	67.5/67.6	88.8/89.1	PYTA/B
C3985	2	73.1/71.2	95.0/93.5	RDTA/B
C4114	2	72.0/72.4	94.8/94.3	RETA/B

Heat No.	Yield Strength (ksi)	Ultimate Strength (ksi)	Test Code
Welds			
Type B-4 mod			
IP2815	66.2	82.0	XO
IP2809	66.2	82.0	XO
13253	65.7	81.6	BV
33A277	67.7	81.3	BB
90099	77.0	89.5	BC
Covered electrode type E8018			
Lot No.			
EAGH	77.6	90.0	NF
LACH	70.5	85.0	FJ
IOBJ	70.8	83.2	BA
ICJJ	70.9	82.4	BF

R.4.6 IMPACT PROPERTIES

A. SA-533, Grade B, Class 1, Plate Material in Beltline Region

Location	Plates	Drop Weight NDTT[a]	ASME Code and Spec Requirements
Lower shell course	305-04A	-10°F or less	+10°F or less
	305-04B	-10°F or less	+10°F or less
	305-04C	-10°F or less	+10°F or less
Lower intermediate shell course	305-02D	-40°F or less	+10°F or less
	305-03A	-20°F	+10°F or less
	305-03B	-40°F	+10°F or less

B. Weld Material Employed in Vessel Beltline Region

Electrode Type and Identification	Charpy V Test Values (ft-lb)	Test Temperatures	Requirements
Covered electrode type E8018 lot nos.			
EAGH	119, 120, 127	10°F	30 ft-lb at + 10°F
LACH	125, 119, 119	10°F	30 ft-lb at + 10°F
IOBJ	120, 121, 126	10°F	30 ft-lb at + 10°F
ICJJ	121, 120, 128	10°F	30 ft-lb at + 10°F
Flux electrode type B-4 mod (Heat/Flux/Lot)			
IP2815 and IP2809/1092/3854	67, 79, 79	10°F	30 ft-lb at + 10°F
13253/1092/3791	85, 77, 81	10°F	30 ft-lb at + 10°F
33A288/0091/3977	111, 106, 113	10°F	20 ft-lb at + 10°F
90099/0091/3977	56, 30, 52	10°F	30 ft-lb at + 10°F

a. NDTT - Nil ductility transition temperature.

Some of the impact data requested were not required to be determined by the specifications applicable at the time of the vessel construction. The reference nil ductility temperature (RT_{NDT}) requested by the Nuclear Regulatory Commission is defined as the larger of the dropweight (T_{NDT}) or the temperature where the material exhibits 50 ft-lb or 35-mil lateral expansion minus 60°F (T_{cv} - 60°F). This term has been developed to characterize the transition temperature and requires a full Charpy impact transition curve to determine the greater of the 50 ft-lb or 35-mil later expansion index temperatures. Also, the required Charpy test specimens for plate material must be oriented transverse to the principal rolling direction.

Using the available impact test data taken in accordance with the requirements of the code to which this vessel is designed and manufactured, RT_{NDT} values are determined using the procedures described in HNP-2-FSAR paragraph 5.2.4.1.1.

Based on this method, the highest value for the unirradiated RT_{NDT} of the core beltline region is 10°F. The data reported for the plate material give a maximum dropweight NDTT of -10°F. However, the Charpy data for the limiting beltline plate, when converted to equivalent transverse values, gives a value of (T_{cv} - 60°F) of 10°F.

General Electric Topical Report NEDO-32205-A, Revision 1, "10 CFR 50 Appendix G Equivalent Margin Analysis for Upper Shelf Energy in BWR/2 through BWR/6 Vessels," addresses beltline materials with low or unknown upper shelf energies (USE). NEDO-32205 was approved by the NRC in December 1993. Georgia Power Company (GPC) determined the analysis performed in this NEDO is applicable to Plant Hatch Units 1 and 2 considering operation at 2558 MWt. Therefore, GPC adopted NEDO-32205, Revision 1, as the HNP-1 licensing basis for demonstrating compliance with the USE requirements of 10 CFR 50, Appendix G. As the exclusive operating licensee, Southern Nuclear Operating Company adopts this conclusion.

R.4.7 PLATE EQUIVALENT MARGIN ANALYSIS (INCLUDING UPRATED POWER CONDITION)

BWR/3-6 PLATE

Surveillance Plate USE:

%Cu = 0.12

1st Capsule Fluence = 2.4×10^{17} n/cm^2

2nd Capsule Fluence = 4.6×10^{17} n/cm^2

Unirradiated to 1st Capsule Measured % Decrease = 4 (Charpy Curves)
Unirradiated to 2nd Capsule Measured % Decrease = -5 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 9
2nd Rev 2 Predicted % Decrease = 10

Limiting Beltline Plate USE:

%Cu = 0.17

32 EFPY Fluence = 1.8 x 10^{18}n/cm^2

Rev 2 Predicted % Decrease = 18

Adjusted % Decreased = N/A

Note: 18% ≤ 21%, thus, vessel plates are bounded by equivalent margin analysis.

R.4.8 WELD EQUIVALENT MARGIN ANALYSIS (INCLUDING UPRATED POWER CONDITION)

BWR/2-6 WELD

Surveillance Weld USE:

%Cu = 0.28

1st Capsule Fluence = 2.4 x 10^{17}n/cm^2

2nd Capsule Fluence = 4.6 x 10^{17}n/cm^2

Unirradiated to 1st or 2nd Capsule Measured % Decrease = Unknown
1st to 2nd Capsule Measured % Decrease = -16 (Charpy Curves)

1st Rev 2 Predicted % Decrease = 19
2nd Rev 2 Predicted % Decrease = 22

Limiting Beltline Weld USE:

%Cu = 0.28

32 EFPY Fluence = 1.8 x 10^{18}n/cm^2

Rev 2 Predicted % Decrease = 28

Adjusted % Decreased = N/A

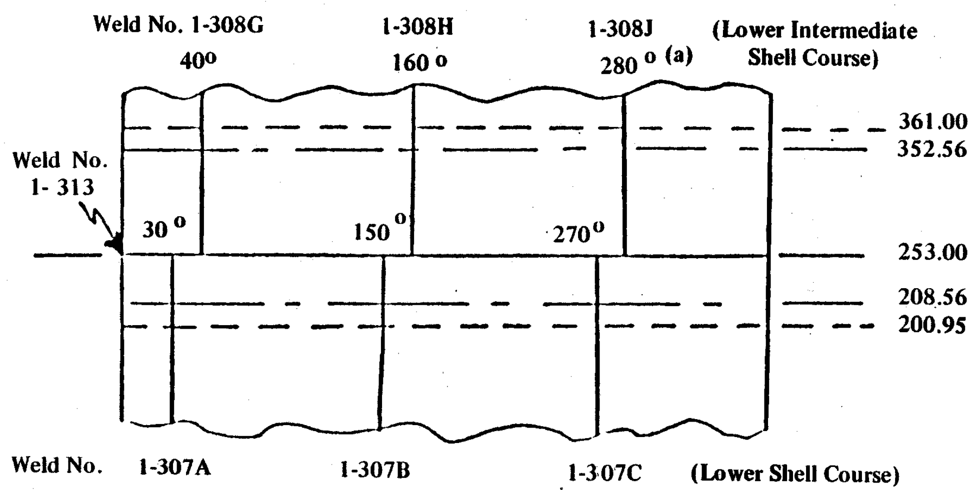
Note: 28% ≤ 34%; thus, vessel welds are bounded by equivalent margin analysis.

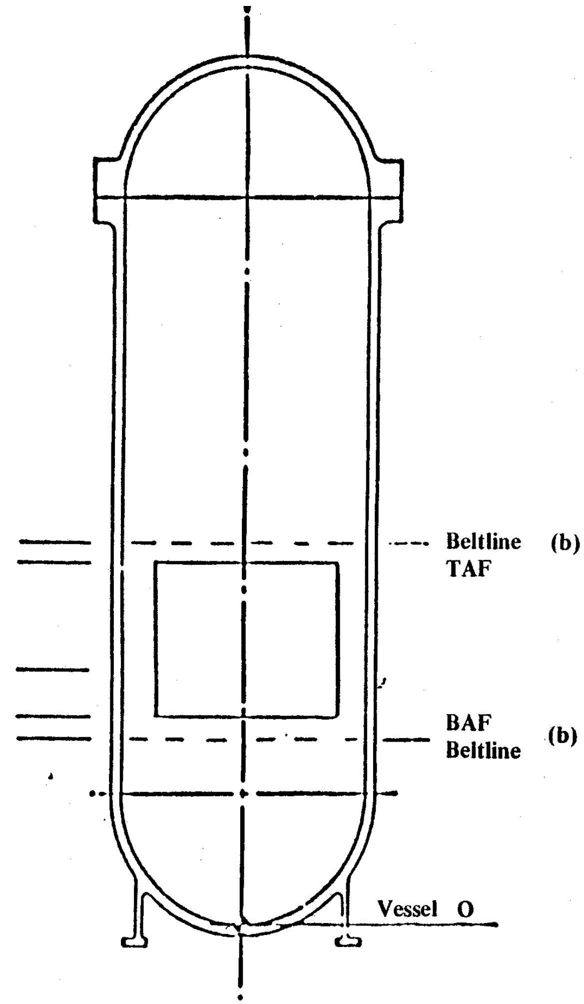
Beltline defined using 0.35% copper
w/(n/cm^2) = 2.25 x 10^{17} at 50° Shift.
BWR/6 vessel Fluence Doc. No. 166B7464
(218) used to ratio beltline location.

All Plates Alloy Steel per A533 Gr B C1 1.

Lower Intermediate Shell Course – 308-06
(Shell Plates – 2 x 305-03, 1 x 305-02)

Lower Shell Course – 307-01
(Shell Plates – 3 x 305-04)





a. Three welds equally spaced—not necessarily at azimuth shown. Numbers are Combustion Engineering drawing numbers unless otherwise defined.
b. Beltline definition per 10 CFR 50 appendix G.

REV 19 7/01

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UNIT 1

VESSEL BELTLINE REGIONS

FIGURE R.4-1

R.5 DETERMINATION OF FAST NEUTRON FLUX AND FLUENCE - HATCH 1 POWER STATION

The HNP-1 fluence model was developed using the BWRVIP developed Radiation Analysis Modeling Application (RAMA) methodology which has been approved by the NRC as compliant with Regulatory Guide 1.190. The projected fluence calculated from this model is used to project nil ductility temperature shifts for plant operation out to the end of licensed operation (EOL). The model is updated periodically to include updated operating history and fuel cycle data[1]. The HNP-1 RAMA model results include a comparison of predicted versus plant specific measurements of flux wire tested following cycles 1, 8, and 16. Combining all flux wire measurements yielded an average calculated-to-measured ratio of 0.96 with a standard deviation of ±14%. The combined uncertainty (1σ) for the HNP-1 reactor pressure vessel fluence is 9.4% for energy >1.0 MeV with no statistical significant bias in the results.

References 2 and 3 contain descriptions of historical determination of neutron fluence prior to the development of the HPN-1 RAMA model.

REFERENCES

1. Edwin I. Hatch Unit 1 Fluence Evaluation at end of cycle 25 and 49.3 EFPY, document number SNC-HA1-002-R-001 revision 0 dated October 5, 2012.

2. “Fast neutron cross section determination for BWRs using neutron dosimeters”, by G. C. Martin, November 11, 1993 (FMT Transmittal 93-212-0045).

3. “Re-determination of Fast Neutron Flux Density and Fluence using Localized Power History: Hatch 1 Nuclear Power Plant”, by G. C. Martin, April 4, 1985 (CMT Transmittal No. 85-212-0011).

R.6 COMPARISON WITH ASTM E-185-70

The following is a comparison of the surveillance test program with ASTM E-185-70, Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels.

(3.1) Test specimens are taken from a plate sample of the same heat and usually from the same plate as one of the vessel wall plates in the reactor core region. The sample plate is welded with the same materials and procedures as a longitudinal butt weld in the core region.[a]

(3.1.1) Except for forming, the test plate represents all of the fabrication processes to which the vessel plate is subjected. The vessel manufacturer quenches and tempers after forming so the forming operation has no effect on final part properties. In addition, the test plate sample is subjected to thermal transients representing the anticipated cumulative stress relief heat treatment.

(3.1.2) Test specimens taken from the test plate represent the base metal, heat-affected zone (HAZ), and weld material.

The plate material is not tested before selection. Pretesting would impose unnecessarily large material and testing costs on the surveillance program. Weld procedures and materials duplicate actual fabrication.

The test specimens are located vertically in the highest fluence area. Circumferentially, the specimens are placed where access dictates, not necessarily at the highest fluence. GE supplies one extra baseline set of specimens as spares (table R.6-1), not two sets.

All specimens are identified and complete documentation is available.

(3.1.3) This is a new requirement. Since the order for the HNP-1 reactor vessel material has been placed earlier and does not request this extensive an analysis, the requirement of this paragraph is not met.

(3.2) The surveillance test specimens conform to the requirements of this paragraph, except that the HAZ impact specimens have the notch at the fusion line instead of 1/32 in. away from this line.

The weld metal tensile specimen is oriented parallel to the weld. All other specimens are oriented parallel to the plate rolling direction, transverse to the weld. The notch of the impact specimen is perpendicular to the weld surface.

(3.3) The number and type of test specimens for the present surveillance program is presented in table R.6-1. This program provides for 8 to 12 impact specimens per test set instead of the suggested 15 minimum. GE's experience indicates that this quantity is adequate.

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a. Numbers in parentheses refer to paragraphs of ASTM E-185-70.

(3.4) It is not the intent of the surveillance program to perform any research and development in conjunction with surveillance; therefore, no correlation monitors are used in this program.

(4) Sample containers with the specimens are mounted as close as practical to the inner surface of the vessel wall and as close as possible to the zone of highest fluence to best duplicate the vessel wall conditions under maximum integrated neutron flux.

(4.2) These paragraphs do not apply to the GE BWR. No specimens are exposed to accelerated irradiation.

(4.3) Thermal control specimens were a part of earlier test programs. After a review of the results, these specimens were discontinued.

(4.4) The BWR is a constant-temperature system and no temperature monitoring is required. The specimens are hermetically sealed in an inert gas (welding quality helium) environment in a thin-wall stainless steel capsule which is not buoyant and which does not present any problem when removing the irradiated specimens. All specimens are encapsulated in tight containers; tensile specimens have aluminum spacers. These steps are taken to keep gamma heating as close as possible to vessel wall conditions.

Present vessel design has provisions for later insertion of surveillance material. After vessel assembly and internals installation, the sample containers can be withdrawn. As seen in table R.6-1, one container was added with reconstituted samples in 1997.

(4.5) The vessel wall and all test specimens are low-alloy ferrite steel. No stainless steel samples are used. Therefore this paragraph is not applicable.

(4.6) The Plant Hatch schedule for removal of the Unit 1 surveillance capsule is given by the integrated surveillance program (ISP) and is provided in table R.6-2.

This program was developed by the BWR Vessel and Internals Project in 1998, approved in 2002, and subsequently modified to account for 40-60 year operating periods within the BWR fleet. The ISP combines all the participating US BWR surveillance programs into a single integrated program and adds data from a supplemental surveillance program (SSP). The ISP has been designed to meet the criteria for an integrated surveillance program in 10 CFR 50 Appendix H.

A matrix of capsules containing the representative weld and plate materials and the planned schedules for withdrawing and testing is provided in table R.6-3. The overall ISP, as documented in references 1 and 2, replaced the original material and surveillance monitoring program with an integrated program using host reactor capsules containing the selected materials. The -A suffix for each report indicates NRC approval and the final reports include the NRC safety evaluation documenting staff review and approval.

The first capsule was withdrawn after 5.7 EFPYs and the second capsule after 14.3 EFPYs. The specimen test results are reported in General Electric Report NEDC-30997 and GE-NE-B1100691-01R1, respectively.

(5.1) Dosimeters measuring the integrated neutron flux are part of the specimens. Irradiation induced temperature is of no consequence in a BWR; therefore, it is not measured. Evaluation of the radiation spectrum is a development, not a surveillance function, and therefore is not done.

(5.2) One each of iron, nickel, and copper flux monitoring wires are placed in each impact specimen capsule in order to provide a cross-check of one determination against another.

(6.1) The tests are conducted in accordance with ASTM E-185.

(6.2) The test temperature is 550°F (vessel operating temperature), when possible.

(7.1) The tests are conducted in accordance with ASTM E-185.

(7.2) The surveillance program and interpretation of the tests are based on 30 ft-lb Charpy impact test results. These data indicate any significant changes in NDTT, if any occur.

(8) The test report is written in accordance with ASTM E-185.

REFERENCES

1. BWRVIP-86-A; BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan EPRI Product 1003346, October 2002.

2. BWRVIP-86, Revision 1-A; BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan EPRI Product 1025144, October 2012.

TABLE R.6-1

SPECIMENS FURNISHED FOR SURVEILLANCE PROGRAM

Reactor Group No.	Type Specimen	No. of Specimens Base	Weld	HAZ
	Unirradiated baseline specimens			
	C[a]	12	12	12
	T[b]	3	3	3
	In-reactor specimens			
1. (Removed 12/84 at 5.7 EFPYs Fluence = 2.4×10^{17} n/cm^2	C	12	12	12
	T	2	2	2
2. (Removed 3/96 at 14.3 EFPYs Fluence = 4.6×10^{17} n/cm^2	C	8	8	8
	T	2	2	2
3.	C	8	8	8
	T	2	2	2
4. Reconstituted capsules installed in 1997	C	8	8	
	T	3	3	
	Out-of-reactor spares			
	C	12	12	12
	T	3	3	3
	Total specimens			
	C	52	52	52
	T	12	12	12

a. C = standard Charpy V-notch impact specimen.
b. T = 1/4-in. gage diameter tensile specimen.

TABLE R.6-2

ISP CAPSULE TEST SCHEDULE

ISP Capsule	Year to be Withdrawn or Tested																			
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Later**
Browns Ferry 2		X	------------------------->>									**X**								
Cooper																	**X**			
Dresden 3			X	------------------------->>													**X**			
Duane Arnold														**X**						
Hatch 1																	**X**			
Hatch 2		X	------------------------->>															**X**		
Hope Creek					X	------------------------->>									**X**					
LaSalle 1						X	------------------------->>				**X**									
Monticello				X	----------->>		**X**													
Peach Bottom 2			X	------------------------->>															**X**	
Perry								X	------------------->>				**X**							**X (2026)**
River Bend			**X**		X	------------------------->>														**X (2025)**
Susquehanna 1			X	------------------------->>								**X**								
SSP-A				**X**																
SSP-B				**X**																
SSP-C				**X**																
SSP-D	**X**																			
SSP-E		**X**																		
SSP-F		**X**																		
SSP-G	**X**																			
SSP-H	**X**																			
SSP-I		**X**																		

Notes:

1. Bold X indicates the schedule under the ISP; arrows indicate shifts from the existing schedule.
2. Browns Ferry 2 was scheduled to withdraw its second capsule in 2001; to increase fluence per NRC Staff recommendations, the ISP delays withdrawal until 2011.
3. Dresden 3, Hatch 2, Hope Creek, LaSalle 1, Monticello, Peach Bottom 2, and Susquehanna 1 final capsule withdrawals are deferred to increase capsule fluence.
4. River Bend withdrew a capsule in 2000 and will test and report the results in 2003.
5. River Bend was scheduled to withdraw its second capsule in 2004, soon after withdrawing its first; to increase fluence per NRC Staff recommendations, the ISP delays withdrawal until 2025.
6. Cooper, Duane Arnold, and Hatch 1 are scheduled for third capsule withdrawals as shown, based on NRC Staff recommendations.
7. Year for capsule withdrawal is approximate; to be coordinated with plant outage schedule.

TABLE R.6-3

ISP TEST MATRIX

TARGET VESSEL WELDS AND PLATES

SURVEILLANCE CAPSULES	Browns Ferry 2 weld	Browns Ferry 2 plate	Browns Ferry 3 weld	Browns Ferry 3 plate	Brunswick 1 weld	Brunswick 1 plate	Brunswick 2 weld	Brunswick 2 plate	Clinton weld	Clinton plate	Cooper weld	Cooper plate	Dresden 2 weld	Dresden 2 plate	Dresden 3 weld	Dresden 3 plate	Duane Arnold weld	Duane Arnold plate	Enrico Fermi 2 weld	Enrico Fermi 2 plate	FitzPatrick weld	FitzPatrick plate	Grand Gulf weld	Grand Gulf plate	Hatch 1 weld	Hatch 1 plate	Hatch 2 weld	Hatch 2 plate	Hope Creek weld	Hope Creek plate	LaSalle 1 weld	LaSalle 1 plate	LaSalle 2 weld	LaSalle 2 plate	Limerick 1 weld	Limerick 1 plate	Limerick 2 weld	Limerick 2 plate	Monticello weld	Monticello plate	Nine Mile Point 1 weld	Nine Mile Point 1 plate	Nine Mile Point 2 weld	Nine Mile Point 2 plate	Oyster Creek weld	Oyster Creek plate	Peach Bottom 2 weld	Peach Bottom 2 plate	Peach Bottom 3 weld	Peach Bottom 3 plate	Perry weld	Perry plate	Pilgrim weld	Pilgrim plate	Quad Cities 1 weld	Quad Cities 1 plate	Quad Cities 2 weld	Quad Cities 2 plate	River Bend weld	River Bend plate	Susquehanna 1 weld	Susquehanna 1 plate	Susquehanna 2 weld	Susquehanna 2 plate	Vermont Yankee weld	Vermont Yankee plate	WNP-2 weld	WNP-2 plate
Browns Ferry 2	1	1	1	1																																																																
Browns Ferry 3																																																																				
Brunswick 1																																																																				
Brunswick 2																																																																				
Clinton																																																																				
Cooper											1	1													1																					1																						
Dresden 2																																																																				
Dresden 3													1		1																																								1		1											
Duane Arnold						1		1									1	1																				1												1														1				1
Enrico Fermi 2																																																																				
FitzPatrick																																																																				
Grand Gulf																																																																				
Hatch 1																				1						1																																										
Hatch 2																											1	1													1				1																							
Hope Creek																													1	1																																						
LaSalle 1																						1									1	1																						1														
LaSalle 2																																																																				
Limerick 1																																																																				
Limerick 2																																																																				
Monticello																																								1																												
Nine Mile Point 1																																																																				
Nine Mile Point 2																																																																				
Oyster Creek																																																																				
Peach Bottom 2																																				1								1			1	1																				
Peach Bottom 3																																																																				
Perry																							1	1																			1								1	1																
Pilgrim																																																																				
Quad Cities 1																																																																				
Quad Cities 2																																																																				
River Bend					2		2		1	1																								1	1		1		1										1										1	1			2				1	
Susquehanna 1																																	1																												1	1			1	1		
Susquehanna 2																																																																				
Vermont Yankee																																																																				
WNP-2																																																																				
SSP					1	2	1	2	2		2			1		1	2	2	1		1		2	2	2										2		2	2	2			1	2						2	2	2	2	1			1		1	2				1	2			2	2

1 Selected to be in final ISP test matrix

2 Capsule(s) which contain the same heat as the Representative Material and whose results will also be considered