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MURRAY R. EDELMAN
VICE PRESIDENT
NUCLEAR

April 2, 1985
PY-CEI/NRR-0227 L

Mr. B. J. Youngblood, Chief
Licensing Branch No. 1
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Perry Nuclear Power Plant
Docket Nos. 50-440; 50-441
FSAR Technical Specifications
Related Changes

Dear Mr. Youngblood:

This letter and its attachments are provided to support your Technical Specification review effort. Attached are proposed FSAR pages which reflect changes resulting from our in-house review.

These changes will be incorporated in FSAR Amendment 18, which is scheduled for the week of April 8, 1985. If you have any questions, please feel free to call.

Very truly yours,

A. Kaplan for

Murray R. Edelman
Vice President
Nuclear Group

MRE:njc

Attachment

cc: Jay Silberg, Esq.
John Stefano (2)
J. Grobe

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1/1

April 2, 1985

TECHNICAL SPECIFICATION RELATED CHANGES TO FSAR

Section	Subject
3.1	Conformance with NRC General Design Criteria
3.7	Seismic Design
3.8	Design of Category 1 Structures
3.9	Mechanical Systems and Components
3.11	Environmental Qualification of Mechanical and Electrical Equipment
5.2	Integrity of Reactor Coolant Pressure Boundary
5.4	Component and Subsystem Design
6.2	Containment Systems
6.5	Fission Product Removal and Control Systems
Chapter 7	Instrumentation and Controls Systems
Chapter 8	Electrical Power
15.1	Decrease in Reactor Coolant Temperature

purposes, however, these cross-ties are so arranged that they do not affect the safety of either unit.

j. Auxiliary Boiler. A common auxiliary boiler is provided to meet the heating requirements of both units. This is non-safety related equipment that does not affect the safe shutdown of either or both units.

k. Standby Liquid Control Transfer System. This is a common system used for providing a makeup volume of sodium pentaborate solution to both Unit 1 and 2 standby liquid control system storage tanks. The auxiliary mixing tank of this system is designed non-safety class, Seismic Category I. Piping and components installed for transferring solution to the storage tanks are designated safety class, Seismic Category I.

l. Control Room HVAC System, Emergency Recirculation Mode. Both Unit 1 and 2 control rooms share this system which is composed of two, 100 percent capacity filter trains, activated on receipt of an emergency signal. Portions of this system are designated safety class, Seismic Category I, as reflected in Table 3.2-1.

m. Annulus Exhaust Gas Treatment System (AEGTS). This system is designed with two redundant exhaust trains, one directing exhaust to the Unit 1 main vent, and the other directing exhaust to the Unit 2 main vent. Both Unit 1 and 2 have an AEGTS that is designated safety class, Seismic Category I.

It is concluded that the above discussed shared facilities do not impair the ability of safety equipment of either unit to perform their safety functions and therefore meet the requirements of Criterion 5.

For further discussion, see the following sections:

a.	General Description of Plant	1.2
b.	Instrumentation and Controls	7.0
c.	Electric Power	8.0
d.	Fuel Storage and Handling	9.1

e.	Spent Fuel Pool Cooling and Clean-up System	9.1.3
f.	Water Systems	9.2
g.	Compressed Air Systems	9.3.1
h.	Process Sampling System	9.3.2
i.	Radioactive Waste Management	11.0
j.	Standby Liquid Control System	9.3.5
k.	Ventilation System Design	6.4.2.2
l.	Secondary Containment	6.5.3.2

3.1.2.2 Group II, Protection by Multiple Fission Product Barriers (Criteria 10-19)

3.1.2.2.1 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.

as the reactor and its auxiliary systems, engineered safety features, turbine generator, steam and power conversion systems and station electric distribution boards.

The control room is located in a Safety Class 3, Seismic Category I structure. Safe occupancy of the control room during abnormal conditions is provided for in the design. Adequate shielding is provided to maintain tolerable radiation levels in the control room, in the event of a design bases accident, for the duration of the accident.

The control room ventilation system has redundant control loops which serve both Unit 1 and 2 control rooms. Each ventilation loop is provided with radiation, toxic gas (chlorine and ethylene oxide) and smoke detectors with appropriate alarms and interlocks. Provision is made for the control room air to be recirculated through HEPA and charcoal filters in the emergency recirculation mode.

The control room will be continuously occupied by qualified operating personnel under all operating and accident conditions. In the unlikely event that the control room must be vacated and access is restricted, instrumentation and controls are provided outside the control room to safely perform a hot shutdown and a subsequent cold shutdown of the reactors.

The above demonstrates that the control room design meets the requirements of Criterion 19.

For further discussion, see the following sections:

a.	General Plant Description	1.2
b.	Control Building Design	3.8
c.	Habitability	6.4
d.	Instrumentation and Control	7.0
e.	Shutdown from Outside Control Room	7.4
f.	Fire Protection	9.5.1

b. Suppression Pool Cooling - limits the temperature within the containment by removing heat from the suppression pool water by means of the RHR heat exchangers. Either or both redundant RHR heat exchangers can be manually activated.

The redundancy and capability of the offsite and onsite electrical power systems for the residual heat removal system is presented in the evaluation against Criterion 34.

For further discussion, see the following sections:

a.	Residual Heat Removal System	5.4.7
b.	Containment Systems	6.2
c.	Standby A-C Power Supply and Distribution	8.0
d.	Water Systems	9.2
e.	Accident Analysis	15.0

3.1.2.4.10 Criterion 39 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the sumps, spray nozzles, and piping to assure the integrity and capability of the system.

3.1.2.4.10.1 Evaluation Against Criterion 39

Provisions are made to facilitate periodic inspections of active components and other important equipment of the containment heat removal systems. During plant operations, the pumps, valves, piping, instrumentation, wiring and other components outside the drywell can be visually inspected at any time and will be inspected periodically. The testing frequencies of most components will be correlated with the component inspection.

The spray rings and nozzles of the RHR containment spray system are located under the reactor building dome. An air connection is provided on the supply piping to the spray rings for testing the spray nozzles. Functional operability

3.1.2.4.13.1 Evaluation Against Criterion 42

With the exception of ductwork and fans located in the drywell, all equipment of the ventilation and purge systems and the combustible gas control system can be inspected during normal plant operation.

The Containment Atmosphere Cleanup Systems, including the annulus exhaust gas treatment system are operated continuously during plant operation with the exception of the containment vessel and drywell purge system and can be monitored for satisfactory operation. Components of the combustible gas control system will be periodically inspected and tested to ensure continued availability. Redundant components and power supplies are provided for these systems.

The design of these systems therefore meets the requirement of Criterion 42.

For further discussion, see the following sections:

a.	General Plant Description	1.2
b.	Containment Functional Design	6.2.1
c.	Secondary Containment Functional Design	6.2.3
d.	Combustible Gas Control in Containment	6.2.5
e.	Fission Product Control Systems	6.5.3
f.	Reactor Building Ventilation Systems	9.4.6
g.	Process and Effluent Radiation Monitoring and Sampling Systems	11.5

3.1.2.4.14 Criterion 43 - Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the

recording system will be located in the electrical equipment room in the intermediate building. Operation of the magnetic tape recorder system is controlled by two seismic triggers that activate the recorders upon detection of an acceleration of 0.005g or greater. A magnetic tape playback system converts the magnetic tape record to an analog strip chart record for prompt seismic analysis. During normal plant operation the system remains in a ready state unless activated by the seismic triggers. The triaxial time history accelerograph is powered from a non-Class 1E 120 volt a-c power source. The recording equipment is equipped with an internal battery which is trickle charged from the non-Class 1E power supply.

Triaxial accelerometer of the time-history accelerograph system (shown in Figure 3.7-17) are located, one each, at the following locations:

a. Reactor building foundation mat in the fuel handling area of the intermediate building at elevation 575'-10" (VE-D51-N101).

b. On the containment vessel in the annulus area at elevation 682'-0" (VE-D51-N111).

3.7.4.2.2 Triaxial Peak Accelerograph

Triaxial peak accelerographs permanently record peak accelerations at the locations indicated below. Following an earthquake, the recorded data is retrieved for analysis. No electric power is required for triaxial peak accelerograph operation.

Triaxial peak accelerographs (shown in Figure 3.7-17) are located, one each, at the following locations:

a. HPCS pump base mat in the auxiliary building at elevation 568'-4" (VR-D51-R140).

b. On the recirculation pump in the reactor building at elevation 591'-2-1/4" (VR-D51-R120).

c. On the HPCS piping in the reactor building at elevation 631'-1-1/4" (VR-D51-R130).

3.7.4.2.3 Triaxial Response Spectrum Recorder

Triaxial response spectrum recorders (shown in Figure 3.7-17), capable of permanently recording peak response as a function of frequency for both horizontal motions and vertical motion, are provided, one each, at the following locations:

a. On the reactor building foundation mat in the intermediate building at elevation 574'-11" (VR-D51-R160).

b. At a recirculation pump piping support in the reactor building at elevation 630'-1" (VR-D51-R170).

c. On the HPCS pump base mat in the auxiliary building at elevation 568'-4" (VR-D51-R180).

d. On the RCIC pump base mat in the auxiliary building at elevation 568'-4" (VR-D51-R190).

Each triaxial response spectrum recorder will record 12 frequencies, 1/3 of an octave apart, beginning with 2 Hertz and ending with 25.4 Hertz.

3.7.4.2.4 Triaxial Seismic Switch

A triaxial seismic switch, located on the reactor building foundation mat, is provided to actuate an alarm in the control room when the OBE acceleration is exceeded. This switch is located in the intermediate building at elevation 575'-10" (Figure 3.7-17, VS-D51-N150). The setpoint for this switch is 0.075g in the horizontal axes and 0.05g in the vertical axis.

Criteria for the selection of types and locations of seismic instrumentation are in accordance with Regulatory Guide 1.12. Where multiple locations for a particular instrument are possible, the location selected is based upon analytical results which show that an amplified response is expected at the selected location. If an earthquake occurs, the recorded responses of the

previously discussed seismic instrumentation, except for the seismic trigger and triaxial seismic switch, are compared to calculated responses as discussed in Section 3.7.4.4.

For instruments using a bracket or plate as a mounting adapter (shown in Figure 3.7-17), Table 3.7-13 presents the calculated lowest natural frequency (of three dimensions) of each mechanical system (adapter bracket or plate, plus instrument). For instruments not using a bracket or plate as a mounting adapter, the instruments are rigidly bolted to the concrete or steel surface monitored in accordance with the instrument manufacturer's instructions.

Instrument assemblies are specified and designed to be free of spurious resonances within the frequency range of the instrument.

Mountings of seismic instrumentation do not affect the measurements obtained.

3.7.4.3 Control Room Operator Notification

Control room signals available to the operator are as follows:

a. An annunciator alarm (visual and audible) is actuated in the control room when the triaxial seismic switch (VS-D51-N150) on the reactor building foundation signals that the OBE acceleration has been exceeded in either of the horizontal directions or in the vertical direction.

b. An annunciator alarm (visual and audible) is actuated in the control room when any of the 12 elements of each triaxial section of the triaxial response spectrum recorder D51-R160-VR on the reactor building foundation mat exceeds the frequency setpoint. Two setpoints are provided for each element. Exceeding the first setpoint illuminates an amber light which indicates that accelerations are approaching design limits. If the second setpoint is exceeded, a red light is illuminated which indicates that the accelerations are exceeding the design limits. The light display indication is located in the control room. The setpoints of the triaxial response spectrum recorder are shown in Table 3.7-14.

c. An annunciator alarm (visual and audible) is actuated when the seismic triggers on the reactor building foundation mat and containment vessel in the annulus area (VS-D51-N101 and VS-D51-N111) detect acceleration greater than 0.05g in either horizontal direction or vertical direction signifying that the triaxial time-history accelerograph recorders have started. These recorders are located in the electrical equipment room in the intermediate building.

3.7.4.4 Comparison of Measured and Predicted Responses

In the event of an earthquake, the control room operator first determines whether or not the OBE acceleration level has been exceeded. This is accomplished by inspection of the indications and alarms described in Section 3.7.4.3. If the OBE acceleration has been exceeded, the plant is shut down to determine whether or not any design acceleration levels have been exceeded. This is accomplished by comparing measured and predicted responses as follows:

a. The triaxial time-history accelerograph at the reactor building foundation and on the containment produces magnetic tapes indicating acceleration as a function of time. These tapes are processed to produce calculated response spectra at appropriate critical damping values. These response spectra are then compared to the measurements recorded by the triaxial response spectrum recorder (designed for 2 percent of critical damping) at the same location. Thus, the actual reactor building foundation response is obtained. This response is then compared to the design response spectra for these locations.

b. Amplified response spectra are calculated for the locations of other sensors in the reactor building using the reactor building dynamic model. These responses are then used as the bases for remodeling, detailed analyses and physical inspections.

TABLE 3.7-13

SEISMIC INSTRUMENTATION

SENSING ELEMENTS(1)

Sensing Element Description	Tag No.	Location	Mounting Type	Lowest Natural Frequency of Mount(2)
Accelerometer	D51-N101	Reactor building foundation in the fuel handling building at elevation 575'-10"	Bolted to bracket which is bolted to shield building wall	(4)
Accelerometer	D51-N111	Containment vessel inside annulus at elevation 686'-0"	Bolted to bracket welded to containment vessel wall	(4)
Seismic Trigger	D51-N100	Reactor building foundation in the intermediate building at elevation 575'-10"	Bolted to bracket which is bolted to shield building wall	(4)
Seismic Trigger	D51-N110	Reactor building foundation in the fuel handling building at elevation 575'-10"	Bolted to bracket which is bolted to shield building wall	(4)
Peak Accelerograph	D51-R120	On the recirculation pump in the reactor building at elevation 604'-8"	Bolted to recirculation pump motor housing	(4)

TABLE 3.7-13 (Continued)

Sensing Element Description	Tag No.	Location	Mounting Type	Lowest Natural Frequency of Mount(2)
Peak Accelerograph	D51-R130	On HPCS piping in reactor building at elevation 631'-1-1/4" (centerline of piping)	Bolted to base mounting plate which is welded to HPCS system pipe hanger.	(4)
Peak Accelerograph	D51-R140	HPCS pump room base mat in auxiliary building at elevation 568'-4"	Bolted to foundation embedment plate	(3)
Seismic Switch	D51-N150	Reactor building foundation in the fuel handling building at elevation 575'-10"	Bolted to bracket which is bolted to shield building wall	(4)
Response Spectrum Recorder with Switches	D51-R160	Reactor building foundation in the intermediate building at elevation 574'-11"	Bolted to triaxial mounting fixture which is bolted to embedment plate	(3)
Response Spectrum Recorder	D51-R170	At recirculation pump piping support in reactor building at elevation 630'-1"	Bolted to triaxial mounting fixture which is welded to support plate	(4)
Response Spectrum Recorder	D51-R180	HPCS pump base mat in auxiliary building at elevation 568'-4"	Bolted to embedment plate triaxial mounting fixture	(3)

TABLE 3.7-13 (Continued)

Sensing Element Description	Tag No.	Location	Mounting Type	Lowest Natural Frequency of Mount(2)
Response Spectrum Recorder	D51-R190	RCIC pump base mat in auxiliary building at elevation 568'-4"	Bolted to embedment plate triaxial mounting fixture	(3)

NOTES:

1. All listed sensing elements are triaxial.
2. Lowest natural frequency, in any of three dimensions, of mounting bracket.
3. This instrument does not use a bracket as a mounting adapter. The instrument is bolted rigidly to a plate embedded in the concrete surface that it monitors and is free from spurious resonances within its frequency range.
4. The instrument uses a bracket or plate as a mounting adapter which is rigidly attached to the structure that it monitors and is free from spurious resonances within its frequency range.

3.8.2 STEEL CONTAINMENT

3.8.2.1 Description of the Containment

3.8.2.1.1 General

The containment vessel is a pressure retaining structure composed of a free standing steel cylinder with an ellipsoidal dome, secured to a steel lined reinforced concrete foundation mat. The mat is the common foundation for the three major structures of the reactor building complex. The free standing portion of the containment vessel is supported by and anchored into the foundation mat, and is designed, fabricated, and erected in accordance with the requirements of ASME Code Section III for class MC components. Neither the shield building (except in the area of the filled annulus) nor the interior structure (except for grating supports) contacts the free standing section of the containment vessel. Sufficient clearance is provided to ensure that contact does not occur during any of the postulated load combinations. Section 3.8.0 gives a description of the reactor building complex structures and Figure 3.8-1 shows their physical relationship.

The containment vessel is designed to contain radioactive material which might be released from the nuclear steam supply system following a loss of coolant accident. The steel containment vessel ensures a high degree of leak tightness during normal operating and accident conditions.

The containment vessel is a safety class structure, as defined in Section 3.2, with an internal free air volume of approximately 1.2×10^6 cubic feet. It is designed for a maximum internal pressure of 15 psig with a coincident temperature of 185°F at accident conditions, and a maximum external pressure differential of 0.8 psi due to accidental operation of the spray headers. The maximum design leakage rate for the containment vessel is 0.2 percent by weight of contained air in 24 hours at 11.31 psig internal pressure (Pa). The design of the containment vessel considers dead load, live load, construction loads, temperature gradients, and the effects of penetrations for both the accident and normal (including seismic) operating conditions.

3.8.2.1.2 Plate Thickness

Final design plate thickness of the containment vessel cylinder and dome is 1-1/2 inches. This is increased to three-inch thick plate around the penetrations in the suppression pool region to provide local reinforcement for containment vessel pressure loads as well as penetration loads. Base liner plates are 3/8 inch thick carbon steel where they are covered by concrete, and half inch thick stainless clad where they are exposed to the suppression pool water.

3.8.2.1.3 Test Channels and Test Assemblies

Steel test channels are provided along welds of the steel liner of the foundation mat so that local leak testing of welds can be performed. The channels are segmented by area. One plug fitting is provided for each area and extends through any covering material, including concrete.

3.8.2.1.4 Personnel Access Air Locks

Two personnel access airlocks with an outside diameter of 9 feet - 7 inches are provided, one at elevation 599'-9", the other at elevation 689'-6".

The personnel access airlocks are welded steel assemblies with double doors, each equipped with double gaskets and designed to provide the capability of leak rate testing the airlock between doors and the cavity between door seals at a pressure of Pa (11.31 psig). Automatic leak rate instruments are located outside the containment end. Since personnel airlock door seals must be tested after each opening, an automatic leak rate monitor (ALRM) is connected to the seal test point on the inner door and outer door of each airlock. The monitors are supplied with instrument air and upon activation of the door interlock switch, the test cycle begins by pressurizing the cavity between each pair of seals to the preset test pressure. At the preset test pressure, the automatic sequence will proceed to the test mode and indicate a pass or fail condition. This result is remotely displayed as an alarm in the control room. After the test cycle, the monitor automatically resets to a ready state for the next door closure. The seal test system is shown schematically in Figure 3.8-100. The airlock doors are

480.19

c. Locks have an interior lighting system which is capable of operating from the emergency power supply.

d. Locks have an emergency communication system.

e. Provisions are made to permit bypassing the door interlocking system to allow doors to be left open when the plant is shut down.

f. The floor system is designed so that it can be easily removed.

g. The locks are designed, fabricated, tested, and inspected in accordance with the ASME Code, Section III, Class MC.

h. Lock hinges are capable of independent three-dimensional adjustment to assist proper seating.

i. Equalizing valves are provided.

j. Provisions are made for in-service leak testing of the door bulkhead penetration gaskets at 11.31 psig (Pa).

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3.8.2.1.5 Equipment Access Hatch

An equipment access hatch with a clear inside diameter of 20 feet is provided at elevation 620'-6" to allow passage of large equipment and components into the containment vessel. The flanged joint between the hatch and cover is designed to accommodate double seals. Periodic leak testing of the hatch is accomplished by pressurizing the space between the seals.

g. Normal Operating Temperature Loads (symbol T_o)

1. Normal operating air (simultaneous) temperatures are:

	Annular Space	Inside Containment
a. Minimum operating, °F	50	60
b. Normal operating, °F	90	90
c. Maximum operating, °F	104	105

2. The suppression pool is limited to the following temperatures by plant operating procedures during normal operation:

   a. Minimum pool temperature of 60°F.

   b. Maximum pool temperature of 134°F with safety relief valve operation.

   c. Maximum normal operating pool temperature of 150°F, continuous safety relief valve blowdown without bubble pressure loads.

h. Loss of Coolant Accident Temperature (T_a) and Pressure (P_a)

The design allows for postulated accident conditions of:

1. Internal pressure, psig	11.31
2. Temperature, °F	184.6 inside the containment vessel 180 outside the containment vessel in annular space

3. Suppression Pool Loads

Suppression pool dynamic loads on the containment vessel are described in Appendices 3A and 3B. Hydrostatic loads are described below in item j.

The steam dryer and shroud head are positioned in the vessel during installation with the aid of vertical guide rods. The dryer assembly rests on steam dryer support brackets attached to the reactor vessel wall. Upward movement of the dryer assembly, which may occur under accident conditions, is restricted by steam dryer hold-down brackets attached to the reactor vessel top head.

3.9.5.1.1.10 Feedwater Spargers

These components are not core support structures or safety class components. They are discussed here to describe flow paths in the vessel. The feedwater spargers are stainless steel headers located in the mixing plenum above the downcomer annulus. A separate sparger is fitted to each feedwater nozzle and is shaped to conform to the curve of the vessel wall. Sparger end brackets are pinned to vessel brackets to support the spargers. Feedwater flow enters the center of the spargers and is discharged radially inward to mix the cooler feedwater with the downcomer flow from the steam separators and steam dryer before it contacts the vessel wall. The feedwater also serves to condense the steam in the region above the downcomer annulus and to subcool the water flowing to the jet pumps and recirculation pumps.

3.9.5.1.1.11 Core Spray Lines and Liquid Control Line

These components are not core support structures. They are discussed here to describe safety class features inside the reactor pressure vessel. The core spray lines are the means for directing flow to the core spray nozzles which distribute coolant during accident conditions. The core spray line associated with the high pressure core spray system also serves as the liquid control line for providing a path for liquid control solution injection.

Two core spray lines enter the reactor vessel through the two core spray nozzles. (See Section 5.4.) The lines divide immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel and are supported by clamps attached to the vessel wall. The lines are then routed downward into the downcomer annulus and pass through the top guide cylinder immediately below the flange. The flow divides again as it enters the center of the semicircular sparger, which is routed halfway around the inside of the top guide cylinder. The two spargers are supported by brackets designed to accommodate thermal

expansion. The line routing and supports are designed to accommodate differential movement between the top guide and vessel. The other core spray line is identical except that it enters the opposite side of the vessel and the spargers are at a slightly different elevation inside the top guide cylinder. The correct spray distribution pattern is provided by a combination of distribution nozzles pointed radially inward and downward from the spargers. (See Section 6.3.) Use of the HPCS spray line for liquid control solution injection facilitates good mixing and dispersion.

3.9.5.1.1.12 Vessel Head Spray Nozzle

This component is not a core support structure. It is included here to describe a safety class feature in the reactor pressure vessel. When reactor coolant is returned to the reactor vessel, part of the flow can be diverted to a spray nozzle in the reactor head. This spray maintains saturated conditions in the reactor vessel head volume by condensing steam being generated by the hot reactor vessel walls and internals. The spray also decreases thermal stratification in the reactor vessel coolant. This ensures that the water level in the reactor vessel can rise. The higher water level provides conduction cooling to more of the mass of metal of the reactor vessel and, therefore, helps to maintain the cooldown rate.

The vessel head spray nozzle is mounted to a short length of pipe and a flange, which is bolted to a mating flange on the reactor vessel head nozzle. (See Section 5.4.)

3.9.5.1.1.13 Differential Pressure Sensing Lines

These components are not core support structures or safety class components. The differential pressure lines enter the vessel through two bottom head penetrations and serve the function within the reactor vessel to sense the differential pressure across the core support plate (described in Section 5.4). One line terminates near the lower shroud with a perforated length below the core support plate to sense the pressure in that region.

The other line terminates immediately above the core support plate and senses the pressure in the region outside the fuel assemblies.

3.9.5.1.1.14 In-Core Flux Monitor Guide Tubes

This component is not a core support structure or safety class component. They provide a means of positioning fixed detectors in the core as well as provide a path for calibration monitors (TIP System).

The in-core flux monitor guide tubes extend from the top of the in-core flux monitor housing (see Section 5.4) in the lower plenum to the top of the core support plate. The power range detectors for the power range monitoring units and the dry tubes for the source range monitoring and intermediate range monitoring (SRM/IRM) detectors are inserted through the guide tubes. A latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The bolts and clamps are welded, after assembly, to prevent loosening during reactor operation.

3.9.5.1.1.15 Surveillance Sample Holders

This component is not a core support structure or a safety class component. The surveillance sample holders are welded baskets containing impact and tensile specimen capsules (see Section 5.4). The baskets hang from the brackets that are attached to the inside wall of the reactor vessel and extend to mid-height of the active core. The radial positions are chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the reactor vessel itself while avoiding jet pump removal interference or damage.

3.9.5.1.1.16 Low Pressure Coolant Injection (LPCI) Lines

This component is not a core support structure but is discussed here to describe the coolant flow paths in the reactor vessel. Three LPCI lines penetrate the core shroud through separate LPCI nozzles. Coolant is discharged inside the core shroud.

Sampling sections are provided for periodic analysis of this water to assure compliance with operation limits of the plant technical specification.

3.11.5.1.2 Design Basis Accident

Water released from the reactor to the suppression pool, following a design basis accident and used for the containment spray, is calculated on the basis of Regulatory Guide 1.7 to have a pH range of 4.5 to 7.0, a conductivity of $\leq$21 µS/CM, oxygen content of $\leq$8 ppm, a carbon dioxide content of $\leq$1 ppm, dissolved hydrogen of $\leq$60 ppb, dissolved salts of $\leq 2 \times 10^{-5}$ g mole/L, and undissolved solids $\leq$9 ppm. No significant concentrations of airborne or waterborne deleterious chemicals have been identified due to the post-LOCA fission products.

The containment spray system provides demineralized water as described above (for containment depressurization), at 5,250 gpm per train (A and B), 120 psig, and 132° F from the containment spray headers. The train A spray may be initiated in conjunction with the RHR operation 10 minutes after a LOCA signal (drywell high pressure and reactor vessel low level 1) either manually or automatically on high containment pressure with the high drywell pressure signal still present. The train B spray initiation logic is identical to train A except that an additional 90 second time delay is utilized in the design. The spray system is manually secured when the pressure transient has been stabilized.

3.11.5.2 Radiation Environment

3.11.5.2.1 Normal Operation

Radiation sources during normal plant operations are identified in Chapters 11 and 12.

Normal radiation environments are provided for both gamma and neutron radiation integrated over 40 years.

3.11.5.2.2 Design Basis Accident

The radiation doses from recirculating fluid lines used to determine the equipment qualification environmental conditions are in accordance with

The secondary detection methods, i.e., the monitoring of pressure and temperature of the drywell atmosphere, are used to detect gross unidentified leakage. High drywell pressure will alarm and trip the isolation logic which will result in closure of the containment isolation valves.

The detection of small identified leakage within the drywell is accomplished by monitoring of drywell equipment drain sump level inflow rate (gpm). The detection channel will activate an alarm in the control room when the total leak rate reaches 25 gpm. This measurement has a sensitivity for detection of leakage increases of 1 gpm over normal background leakage.

The determination of the source of identified leakage within the drywell is accomplished by monitoring the drain lines to the drywell equipment drain sumps from various potential leakage sources. These include upper containment pool seal drain flow, reactor recirculation pump seal drain flow, valve stem leakoff drain line temperatures and reactor vessel head seal drain line pressure. Additionally, temperature is monitored in the safety/relief valve discharge lines to the suppression pool to detect leakage through each of the safety/relief valves. All of these monitors, except the reactor recirculation seal drain flow monitor, continuously indicate and/or record in the control room. All of these monitors will trip and activate an alarm in the control room on detection of leakage from monitored components.

Excessive leakage inside the drywell (e.g., process line break or loss of coolant accident within primary containment) is detected by high drywell pressure, low reactor water level or steam line flow (for breaks down stream of the flow elements). The instrumentation channels for these variables will trip when the monitored variable exceeds a predetermined limit to activate an alarm and trip the isolation logic which will close appropriate isolation valves (see Table 5.2-8).

The alarms, indication and isolation trip functions initiated by the leak detection systems are summarized in Tables 5.2-8 and 5.2-9.

5.2.5.2 Leakage Detection Instrumentation and Monitoring

5.2.5.2.1 Leak Detection Instrumentation and Monitoring Inside Drywell

Leak detection instrumentation and monitoring inside drywell is as follows:

a. Floor Drain Sump Measurement.

The normal design leakage collected in the floor drain sump includes unidentified leakage from the control rod drives, valve flange leakage, component cooling water, air cooler drains, and any leakage not connected to the equipment drain sump. The floor drain sump instrumentation monitors and records sump level and rate of change of level. Abnormal leakage rates are alarmed in the main control room. Collection in excess of background leakage would indicate an increase in reactor coolant leakage from an unidentified source.

b. Equipment Drain Sump.

The equipment drain sump collects only identified leakage. This sump receives piped drainage from pump seal leakoff, reactor vessel head flange vent drain, and valve stem packing leak off. Collection in excess of background leakage would indicate an increase in reactor coolant from an identified source. The equipment drain sump instrumentation is similar to that of the floor drain sump and, in addition, monitors sump drain pump fillup time and pumpout time.

c. Cooler Condensate Drain.

Condensate from the upper two drywell coolers is routed to the floor drain sump and is monitored by use of a flow transmitter which measures flow in the condensate drain line and sends signals for indication and alarm instrumentation in the control room. An adjustable alarm is set to annunciate on the condensate high flow rate at a level exceeding normal flow rate conditions.

5.2.5.8 Safety Interfaces

The Balance of Plant-GE Nuclear Steam Supply System safety interfaces for the leak detection system are the signals from the monitored balance of plant equipment and systems which are part of the nuclear system process barrier, and associated wiring and cable lying outside the nuclear steam supply system equipment.

5.2.5.9 Testing and Calibration

Provisions for testing and calibration of the leak detection system are covered in Chapter 14.

5.2.5.10 Regulatory Guide 1.45 Compliance

The detection of leakage through the reactor coolant pressure boundary, described in the preceeding sections, meets the intent of the Regulatory Guide 1.45. Details of compliance are discussed in the following.

a. Leakage is separated into identified and unidentified categories and total flow rate for each is independently monitored, thus meeting position c.1 of Regulatory Guide 1.45.

b. Small unidentified leaks (5 gpm and less) inside the drywell are detected by temperature changes, pressure changes, drain pump activities, fission product monitoring, and upper two drywell cooler condensate flow monitoring.

   Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

   The 5 gpm leakage rate is the plant Technical Specification limit on unidentified leakage inside the drywell. The leak detection system is fully capable of monitoring the flow rates of 1 gpm and is thus in compliance with position c.2 of Regulatory Guide 1.45.

c. By monitoring floor drain sump level (flow rate), airborne particulate radioactivity, airborne gaseous radioactivity, position c.3 is satisfied.

Isolation and/or alarm of affected systems and the detection methods used are summarized in Tables 5.2-8 and 5.2-9.

d. Monitoring of coolant for radiation in the RHR and RWCS heat exchangers satisfies position c.4. For system details, see Section 7.6.

e. The floor drain sump monitoring, and the upper air cooler condensate monitoring are designed to detect leakage rates of 1 gpm within 1 hour, thus meeting position c.5.

f. The fission products monitoring subsystem is qualified for SSE. The drywell floor drain and equipment drain sump level instrumentation and air coolers are not required to operate during and after seismic events, thus meeting position c.6. It must be noted, however, that administrative procedures can be utilized to verify operability following an event if required.

g. Leakage detection indicators and alarms are provided in the main control room. This satisfies c.7 of General Electric scope of supply. Procedures for converting the various indications to a common leakage equivalent for the operators to satisfy position c.7 are not required based on usage of sump level indication (flow rate) as the primary method of leak detection.

h. The leakage detection system is equipped with provisions to permit testing for operability and calibration during the plant operation using the following methods:

1. Simulation of signals into trip units

2. Comparing channel "A" to channel "B" of the same leak detection method (drywell temperature and pressure monitoring)

3. Checking operability by comparing one method versus another (air cooler condensate flow versus floor drain sump level (flow rate)).

TABLE 5.2-3

SYSTEMS WHICH MAY INITIATE DURING OVERPRESSURE EVENT

System	Initiating/Trip Signal(s)[1]
Reactor Protection System	Reactor trips "OFF" on High Flux
RCIC	"ON" when Reactor Water Level $\geq$ L2
	"OFF" when Reactor Water Level $\leq$ L8
HPCS	"ON" when Reactor Water Level $\geq$ L2
	"ON" when Drywell Pressure $\geq$ 2 psig
	"OFF" when Reactor Water Level $\leq$ L8
Recirculation System	"OFF" when Reactor Water Level < L2
	"OFF" when Reactor Pressure > 1125 psig
RWCS	"OFF" when Reactor Water Level < L2

NOTE:

1. Vessel level trip settings are shown on Figure 5.3-2.

pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Code, Section III.

5.4.5.3 Safety Evaluation

The analysis of a complete, sudden steam line break outside the containment is described in Chapter 15. The analysis shows that the fuel barrier is protected against loss of cooling if main steam isolation valve closure is within specified limits, including instrumentation delay 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, approximately 3 seconds, of the main steam isolation valves is shown to be satisfactory (Chapter 15). The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipe lines included, and reactor power level) are exceeded (see Section 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear system relief valve to open briefly, but the rise in fuel cladding temperature will be insignificant. 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 with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20-inch valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions[2].

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 at settings between 3 seconds and 10 seconds (response time for full closure is set prior to plant operation at 2.5 second minimum, 5.0 second maximum), each valve is tested at 1000 psig line pressure and no flow. The valve is stroked

Testing of the hydrogen analyzers is done periodically by injecting a calibration gas into the sample lines and comparing the known concentration with the analyzer readout.

The hydrogen recombiners are tested every 18 months to check the calibration of the unit and proper operation of the heaters by energizing the unit and allowing temperatures to stabilize at the operating conditions.

Preoperational tests of the combustible gas control system are conducted during the final stages of plant construction prior to initial startup (see Section 14.2). These tests ensure correct functioning of all controls, instrumentation, compressors, recombiners, piping, and valves. System reference characteristics, such as pressure differentials and flow rates, are documented during the preoperational tests and are used as base points for measurements in subsequent operational tests.

In addition, inservice inspection of all ASME, Section III, Class 3 components is done in accordance with Section 6.6.

6.2.5.5 Instrumentation Requirements

Operation of the combustible gas control system is performed manually. On-off status of compressors and position of valves are indicated in the control room. Hydrogen concentration recorders and alarms, flow recorders, low flow, system bypassed alarms and control switches are located in the control room.

Within the first hour after a LOCA both hydrogen analyzers are started manually from the control room. The hydrogen analyzer recorder/switching station is located in the control room on panel H13-P800. The analyzer switching station allows the operator to manually select one of the four sample areas previously discussed. Both hydrogen analyzers alarm high hydrogen concentration at 3 percent hydrogen by volume. This is below the four percent limit in Regulatory Guide 1.7 and thus

TABLE 6.2-28

ADDITIONAL INFORMATION TO BE PROVIDED FOR DUAL CONTAINMENT PLANTS

I.	Secondary Containment Design	
	A. Free volume, ft^3	392,548
	B. Pressure, inches of water gauge	
	1. Normal operation	-0.4
	2. Post-accident	-0.4 inch to -0.24
	C. Leak rate at post-accident pressure, %/day	100
	D. Exhaust fans	
	1. Number	2
	2. Type	Centrifugal
	E. Filters	
	1. Number	2
	2. Type	Charcoal filter train consisting of a demister, roughing filter, electric heating coil, HEPA filters, charcoal filters (4 inches deep), and HEPA filter.
II.	Transient Analysis	
	A. Initial annulus conditions	
	1. Pressure, psia	14.682
	2. Temperature, °F	106
	3. Outside air temperature, °F	95
	4. Thickness of secondary containment wall, inches	36
	5. Thickness of primary containment wall, inches	1.5

TABLE 6.2-32 (Continued)

NOTES (Cont'd)

13. Main steam line isolation valves require that both solenoid pilots be de-energized to close. Accumulator air pressure plus spring act to close valves when both pilots are de-energized. Voltage failure at only one pilot does not cause valve closure. These valves are designed to close fully in 2.5 to 5 seconds (see Section 5.4.5.3).

14. During reactor operation, a blind flange is installed on the outboard end of the transfer tube as the containment boundary.

15. This table does not list valves on test connections. Valves on test connections are listed in Table 6.2-40.

16. This receives a Type B test.

The FHACES and AEGTS are operated continuously during plant normal operation. The CRERS is operated for at least 10 hours each month as recommended by Regulatory Guide 1.52; during this operation of CRERS, the exhaust air is free of radioactive contaminants. Air exhausted or circulated through the charcoal adsorber plenums is not expected to contain enough radioactive contaminants following a DBA to develop decay heat that could ignite the charcoal adsorber material.

The charcoal adsorber plenums are redundant, physically separated and powered from separate Class 1E electrical system Division 4.

In the event smoke from a fire is exhausted through any charcoal filter, the filter will be tested for any degradation in charcoal performance as a result of the smoke. This testing will be performed within a period determined in the technical specifications. If the testing indicates that degradation has occurred beyond acceptable limits, the charcoal will be replaced. For charcoal filters in systems needed to mitigate the consequences of a LOCA, namely the annulus exhaust gas treatment system (AEGTS), the filters will be tested and the charcoal replaced, if required, within a period specified in the technical specifications.

6.5.1.4 Tests and Inspections

Tests and inspections of the CRERS, FHACES, and AEGTS charcoal adsorber plenums are performed prior to startup and on a periodic basis thereafter. Other tests and inspections of these filter systems are discussed in Sections 6.4, 9.4.2 and 6.5.3, respectively.

6.5.1.4.1 Filter and Charcoal Adsorber Tests

HEPA filters are individually tested by an appropriate filter test facility at 100 percent and 20 percent of rated flow, in accordance with the recommendation of Regulatory Guide 1.52. Original or replacement HEPA filters used in the CRERS, FHACES, and AEGTS are tested as indicated above.

TABLE 6.5-7

PRIMARY CONTAINMENT OPERATION FOLLOWING A DESIGN BASIS ACCIDENT

Type of structure	Steel cylinder with ellopsoidal dome secured to a steel lined reinforced concrete foundation mat.
Internal fission product removal systems	None
Free volume of primary containment, ft^3	1.16×10^6 (excluding drywell)
Hydrogen purge system operation	See Section 6.2.5
Containment leakage rate, Vol%/day	0.20
Effectiveness of internal fission product removal systems	Not applicable

m. The Fuel Pool Cooling System (FPCS) - instrumentation and controls monitor water temperature and controls cooling of the fuel pool.

n. Containment Atmospheric Monitoring System - provides instrumentation for detecting and predicting the progression of abnormal occurrences in the containment and for monitoring after postulated accidents. Temperature and pressure sensing are furnished throughout the containment and drywell with adjustable alarm features. Monitoring of the containment atmosphere for radioactivity and radiation is provided in the process and area radiation monitoring systems. Hydrogen analysis instrumentation is provided in combustible gas control system. Suppression pool level instrumentation is provided in suppression pool make-up system.

o. Containment Cooling and Purification System - instrumentation and controls are provided to initiate and control containment vessel and drywell cooling, to manually initiate and control the purge of the containment vessel and drywell and to manually or automatically terminate purge. The system also includes the Annulus Exhaust Gas Treatment System which filters, monitors, and exhausts any gases leaking from the containment vessel.

p. The Main Steamline Isolation Valve-Leakage Control System (MSIVLCS) - instrumentation and controls monitor and control bypass leakage and minimizes the release of fission products to the atmosphere following a loss-of-coolant accident.

q. The Safety Related Display Instrumentation is provided to inform the reactor operator when a manual safety action should be taken or is required and allows assessment of safety system status.

r. The RHRS - Containment Spray Cooling Mode (CSCM) is an automatic or manually initiated subsystem of the RHR system that is provided to condense steam in the containment following a loss-of-coolant accident.

s. The Remote Shutdown System (RSS) provides the capability to assure safe shutdown of the reactor in the event that the control room should become uninhabitable.

TABLE 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY OF SAFETY RELATED SYSTEMS

	GE Design	GE Supply	Others
Reactor Protection Trip System			
Reactor Protection Trip System (RPS)	X	X	
Engineered Safety Features Systems			
Emergency Core Cooling Systems (ECCS)	X	X	
High Pressure Core Spray (HPCS)			
Automatic Depressurization System (ADS)			
Low Pressure Core Spray System (LPCS)			
RHR Low Pressure Coolant Injection (LPCI)			
Containment and Reactor Vessel Isolation Control System (CRVICS)	X	X	X
Process Radiation Monitoring System (PRM) (Portion used for CRVICS)	X	X	X
Emergency Water Systems			
Emergency Closed Cooling Water (ECCW)			X
Emergency Service Water (ESW)			X
Control Complex Heating Ventilation and Air Condition System			X
Combustible Gas Control System			X
Containment Cooling and Purification Systems			X
ESF Building and Area HVAC and Purification System			X
Containment Vacuum Relief System			X
Drywell Vacuum Relief System			X
Suppression Pool Makeup System			X
RHRS Containment Spray Cooling Mode	X	X	
Main Steamline Isolation Valve Leakage Control System (MSIVLCS)	X	X	X
RHRS Suppression Pool Cooling Mode	X	X	
Standby Power Systems	X	X	X
Pump Room Cooling Systems			X
Systems Required for Safe Shutdown			
Standby Liquid Control System (SLCS)	X	X	
RHR Reactor Shutdown Cooling Mode	X	X	
Reactor Shutdown Outside the Control Room (RSS)	X	X	X
Reactor Core Isolation Cooling System (RCIC)	X	X	

TABLE 7.1-1 (Continued)

	GE Design	GE Supply	Others
Safety-Related Display Instrumentation	X	X	X
All Other Safety Related Systems			
Process Radiation Monitoring System			X
Neutron Monitoring System	X	X	
Intermediate Range Monitor (IRM)			
Average Power Range Monitor (APRM)			
Local Power Range Monitor (LPRM)			
Leak Detection	X	X	X
Rod Pattern Control System (RPCS)	X	X	
Recirculation Pump Trip (RPT)	X	X	
Fuel Pool Cooling System (FPCS)			X
Fuel Handling Area Ventilation System			X
Off-Gas Building Exhaust			X
Containment Atmosphere Monitoring System			X
High Pressure - Low Pressure Systems Interlocks	X	X	
Redundant Reactivity Control System	X	X	

TABLE 7.1-2 (Continued)

NOTES:

1. None; new design.

2. System designs are similar except for/that:

   a. Differences in instrumentation ranges and/or trip setting to accommodate difference in reactor vessel size. Instrument zero is 363.5 inches above "TAF" and 533.00 inches above vessel zero for PNPP and Grand Gulf, respectively.

   b. Differences in equipment capacity to accommodate difference in reactor vessel size and/or supporting auxiliary equipment.

   c. Differences in physical configuration and/or the amounts of associated controls. PNPP has two containment spray loops and Grand Gulf has one.

   d. Differences due to difference in core size.

   e. Differences due to the use of multifunction equipment that has been sized to accommodate different vessel size. Pump sizing priority is based on the most rigid of duty requirements.

TABLE 7.1-4

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE WITH REG. GUIDE 1.97, REV. 2 (NSSS DESIGN)

Variable	Type	Category(15)	Qualification	Quality Assurance(2)	Redundancy	Range	Power Supply	Display	Remarks
Reactor Water Level	A,B Note 16								
Wide Range		1	Note 1	Yes	Three Channels	5" to 230" above TAF	1E	Control Room Panel & ERIS	Note 29
Fuel Zone		1	Note 1	Yes	Three Channels	150" below TAF to 50" above TAF	1E	Control Room Panel & ERIS	Note 4
Reactor Pressure	A,B,C Note 16	1	Note 1	Yes	Two Channels	0-1500 psig	1E	Control Room Panel & ERIS	Note 5
Neutron Flux	A,B Note 16								
Average Power Range		2	Note 1	Yes	Eight Channels	10^{12}-10^{14} NV (10^{14} NV >100% power)	IE & Uninter-ruptible	Control Room Panel & ERIS	Note 6
Intermediate Range		2	Note 1	Yes	Eight Channels	10^{8}-10^{13} NV	RPS	Control Room Panel	Note 6
Source Range		2	Note 1	Yes	Four Channels	10^{3}-10^{9} NV	RPS	Control Room Panel & ERIS	Note 6
Control Rod Pos.	B	3	N/A	Commercial Grade	One Display for Each Control Rod	Full in to Full out	Uninter-ruptible	Control Room Panel & ERIS	
Drywell Sump (Equip. Drain-Ident.)	B,C	3	N/A	Commercial Grade	One Channel	0-25 gpm	Instr. bus	Control Room Panel & ERIS	Notes 8 & 28
Drywell Sump (Floor Drain-Unindent.)	B,C	3	N/A	Commercial Grade	One Channel	0-5 gpm	Instr. bus	Control Room Panel & ERIS	Notes 8 & 28
Feedwater Flow	D	3	N/A	Commercial Grade	One Channel (Two loops summed)	0-20x10^{6} lb/hr	Instr. bus	Control Room Panel & ERIS	

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE
WITH
REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
Containment and Drywell Hydrogen Concentration	A,C Note 16	1	Note 1	Yes	Two Channels (four locations each)	0-30% H_2	1E	Control Room Panel & ERIS	
Drywell Pressure	A,B,C,D Note 16								
Narrow Range		1	Note 1	Yes	Two Channels	10" Hg to 5 psig	1E	Control Room Panel & ERIS	
Wide Range		1	Note 1	Yes	Two Channels	30" Hg to 35 psig	1E	Control Room Panel & ERIS	
Suppression Pool Water Temperature	A,D Note 16	1	Note 1	Yes	Two Channels (eight locations each) Note 23	30-230°F	1E	Control Room Panel & ERIS	
Suppression Pool Water Level	A,C,D Note 16								
Narrow Range		1	Note 1	Yes	Two Channels	16.0-19.0 ft	1E	Control Room Panel & ERIS	
Extended Range		1	Note 1	Yes	Two Channels	2.0-24.0 ft	1E	Control Room Panel & ERIS	

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE
WITH
REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
Primary Containment Pressure	A,B,C								
Normal Range		1	Note 1	Yes	Two Channels	10" Hg to 20 psig	1E	Control Room Panel & ERIS	
Wide Range		1	Note 1	Yes	Two Channels	10" Hg to 60 psig	1E	Control Room Panel & ERIS	
Primary Containment Isolation Valve Position	B	1	Note 1	Yes	Two valves, open & closed switches each valve	Open/Closed	1E	Control Room Panel & ERIS	Notes 7 & 22
Containment Effluent Radioactivity-Noble Gases	C	3	N/A	Commercial Grade	One Channel	10^{-6}-10^{-2} μCi/cc	Diesel backed non 1E	Control Room Panel & ERIS	Note 25
Radiation Exposure Rate (inside bldgs. or areas which are in direct contact with primary containment where penetrations and hatches are located)	C	2	Note 1	Yes	Two Channels	1-10^{8} R/hr	1E	Control Room Panel & ERIS	Note 24
Effluent Radiation Noble Gases	C	2	Note 1	Yes	Three Channels	10^{-6}-10^{5} μCi/cc	1E	Control Room Panel & ERIS	Notes 17 & 25
Condensate Storage Tank Level	D	3	N/A	Commercial Grade	One Channel	20,000-470,000 gal.		Uninter-ruptible	Control Room Panel & ERIS
Drywell Atmosphere Temperature	A,D	1	Note 1	Yes	Two Channels (three locations each)	40-440° F	1E	Control Room Panel & ERIS	
Containment Atmos-phere Temperature	A	1	Note 1	Yes	Two Channels (Four locations each)	50-200° F	1E	Control Room, Panel & ERIS	

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE
WITH
REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
Primary Containment Area Radiation Hi-Range	E	1	Note 1	Yes	Two Channels	$1-10^8$ R/hr	1E	Control Room Panel & ERIS	
Reactor Building Area Radiation	E	1	Note 1	Yes	Two Channels	$1-10^8$ R/hr	1E	Control Room Panel & ERIS	
Radiation Exposure Rate (inside bldgs. or areas where access is required to service equipment important to safety)	E	3	N/A	Commercial Grade	One Channel	$10^{-4}-10^4$ R/hr	Diesel backed non 1E	Control Room Panel & Local	Note 21
Airborne Radioactive Materials Released From Plant	E	2	Note 1	Yes	Three Channels per monitor to cover range three release points	$10^{-6}-10^5$ µCi/cc	1E	Control Room Panel & ERIS	Notes 17 & 25
Particulates and Halogens all Identified Plant Release Points with Onsite Analysis Capability	E	3	N/A	Commercial Grade	One Channel	$10^{-3}-10^2$ µCi/cc	Diesel backed non 1E	None	Note 25
Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	C	3	N/A	Commercial Grade	N/A (Sample)	1/2 Tech Spec Limit to 100 times Tech Spec limit, R/hr	Uninter-ruptible	None	Note 27

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE
WITH
REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
Accident Sampling Capability	E								
Gross Activity		3	N/A	Commercial Grade	N/A (Grab Sample)	10μ-10 Ci/ml	Uninter-ruptible	None	
Gamma Spectrum		3	N/A	Commercial Grade	N/A (Grab Sample)	Isotopic Analysis	Uninter-ruptible	None	
Boron Content		3	N/A	Commercial Grade	N/A (Grab Sample)	0-1000 ppm	Uninter-ruptible	None	
Chloride Content		3	N/A	Commercial Grade	N/A (Grab Sample)	0-20 ppm	Uninter-ruptible	None	
Dissolved Hydrogen or Total Gas		3	N/A	Commercial Grade	N/A (Grab Sample)	0-2000 cc(STP)/kg	Uninter-ruptible	None	
Dissolved Oxygen		3	N/A	Commercial Grade	N/A (Grab Sample)	0-20 ppm	Uninter-ruptible	None	
pH		3	N/A	Commercial Grade	N/A (Grab Sample)	1-13	Uninter-ruptible	None	
Hydrogen Content		3	N/A	Commercial Grade	N/A (Grab Sample)	0-10%	Uninter-ruptible	None	
Oxygen Content		3	N/A	Commercial Grade	N/A (Grab Sample)	0-30%	Uninter-ruptible	None	
Gamma Spectrum		3	N/A	Commercial Grade	N/A (Grab Sample)	Isotopic Analysis	Uninter-ruptible	None	

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE WITH REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
RCS Soluble Boron Concentration	B,E	3	N/A	Commerical Grade	N/A (Sample)	0-1000 ppm (Analysis)	Uninter-ruptible	None	Note 20
Analysis of Primary Coolant	C	3	N/A	Commercial Grade	N/A (Sample)	10 µCi/gm-10 Ci/gm or TID 14844 source term in coolant volume	Uninter-ruptible	None	Note 20
Cooling Water Flow to ESF Systems Components	D								
Emergency Closed Cooling Loop Flow		2	Note 1	Yes	One Channel per loop	0-2600 gpm	1E	Control Room Panel & ERIS	
ESW Flow to ECCS HX		2	Note 1	Yes	One Channel per loop	0-3000 gpm	1E	Control Room Panel & ERIS	
ESW Flow to HPCS Diesel HX		2	Note 1	Yes	One Channel	0-1000 gpm	1E	Control Room Panel & ERIS	
ESW Flow to Stdby Diesel HX		2	Note 1	Yes	One Channel per loop	0-1200 gpm	1E	Control Room Panel & ERIS	
Airborne Radiohalogens and Particulates Portable Sampling with Onsite Analysis Capability	E	3	N/A	Commerical Grade	Three Portable Units	Air sampling 10^{-9}-10^{-3} µCi/cc at analysis facility	N/A	None	
Plant & Environs Radiation (Portable Instrumentation)	E	3	N/A	Commercial Grade	Two Portable Detector Units	10^{-3}-10^{4} R/hr	N/A	None	

TABLE 7.1-4 (Cont'd)

SUMMARY INFORMATION INDICATING DEGREE OF COMPLIANCE
WITH
REG. GUIDE 1.97, REV. 2 (OTHERS)

Variable	Type	Category(15)	Qualification	Quality Assurance(14)	Redundancy	Range	Power Supply	Display	Remarks
Plant & Environs Radioactivity	E	3	N/A	Commercial Grade	One Unit	Multi-Channel Gamma Ray Spectrometer	Instr. bus	Local	
Meteorology	E								
Wind Direction		3	N/A	Commercial Grade	Main & Back-up	0-540°	Uninter-ruptible	Control Room Panel & MIDAS	
Wind Speed		3	N/A	Commercial Grade	Main & Back-up	10m, 0-50 mph, 60m, 100 mph	Uninter-ruptible	Control Room Panel & MIDAS	
Estimation of Atmospheric Stability		3	N/A	Commercial Grade	Main & Back-up	-20 to 100°F Delta T -4 to 8°F (60-10m)	Uninter-ruptible	Control Room Panel & ERIS	
Containment & Drywell Oxygen Concentration	C	1	N/A	N/A	N/A	N/A	N/A	N/A	Note 13
Drywell Spray Flow	D	2	N/A	N/A	N/A	N/A	N/A	N/A	Note 26
Isolation Condenser System Shell-Side Water Level	D	2	N/A	N/A	N/A	N/A	N/A	N/A	Note 19
Isolation Condenser System Valve Position	D	2	N/A	N/A	N/A	N/A	N/A	N/A	Note 19
Radiation Exposure Meters (Continuous Indication at Fixed Locations)	E	-	N/A	N/A	N/A	N/A	N/A	N/A	Note 18

TABLE 7.1-4 (Cont'd)

NOTES:

1. Environmental and seismic qualification of Category 1 and 2 variables will be in accordance with the PNPP Equipment Qualification Program.

2. Yes indicates that quality assurance is in accordance with NEDO-11209, NEBG BWR QA Program Description.

3. Deleted.

4. Two existing fuel zone monitors will be upgraded to Category 1 requirements and one additional fuel zone monitor will be included.

5. Pressure indicating switches located on control room backpanels H13-P693 or H13-P694 will be utilized to verify reactor vessel pressure when the two channel readings disagree.

6. Neutron flux monitoring instrumentation (average power range, intermediate range, and source range) at PNPP is installed in accordance with the requirements set forth for Category 2 variables. Adherence to a Category 1 classification for neutron flux will be considered by PNPP based on successful equipment development by a vendor.

7. Primary containment isolation valve position is displayed in the Control Room by in/out lights. Recorders are not utilized for display of this variable.

8. Drywell sump level or drywell drain sump level (identified/unidentified leakage) is not considered a "key variable" since they neither automatically initiate safety-related systems nor do they alert the operator to take safety-related actions. The level of the drain sumps can be a direct indication of breach of the reactor coolant system pressure boundary, but may be ambiguous because there is water in the sumps during normal operation. There is other instrumentation required by Regulatory Guide 1.97 that would indicate leakage in the drywell, such as, drywell pressure, drywell temperature, and primary containment area radiation. Regulatory Guide 1.97 requires instrumentation to function during and after an accident. The drywell sump systems are deliberately isolated at the primary containment penetration upon receipt of an accident signal to establish containment integrity. Therefore, by design, drywell level instrumentation serves no useful accident-monitoring function. Based on the above, this variable will be implemented at PNPP in accordance with Category 3 instead of Category 1 requirements.

9. RHR system valve position lineup will be displayed in the Control Room to verify flow through the containment spray flow loops. Valve position instrumentation will also be implemented using Catetory 2 design criteria.

10. MSIV leakage control system flow instrumentation, in lieu of pressure instrumentation, will be implemented at PNPP to meet the intent of Regulatory Guide 1.97. Leakage flow monitoring is considered to provide less ambiguous indication of proper system operation.

11. Stand-by liquid control system discharge pump pressure, and SLCS tank level, in lieu of flow, will be monitored at PNPP simultaneously to meet the intent of Regulatory Guide 1.97.

12. RHR service water flow will be monitored in lieu of RHR heat exchanger outlet temperature to verify system operation. Heat exchanger bypass valve position will also be verified by Control Room display.

TABLE 7.1-4 (Cont'd)

NOTES (Cont'd)

13. The containment and drywell oxygen concentrate variable is not applicable to PNPP's design since PNPP does not utilize an inerted containment. Therefore, this variable will not be implemented per Reg. Guide 1.97, Rev. 2.

14. Instruments designated as "yes" implements applicable Regulatory Guide requirements for Quality Assurance in Regulatory Guide 1.97, Rev. 2.

15. All Category 1 variables shall have at least one channel continuously recorded.

16. Variables, identified as Type A, have been selected based on developed BWROG generic emergency operating procedures.

17. One channel will utilize an existing monitor with a range of 10^{-6} to 10^{-22} μ Ci/cc and is designed non-safety related, non class 1E. This channel is provided with diesel backed non-class 1E power. (Revision 2 of Regulatory Guide 1.97, subnote 9, permits the preceding.) Instrumentation for the remaining two channels will be added to expand the range from 1.7×10^{-3} to 10^{5} μ Ci/cc. and are designated safety related, Class 1E.

18. BWR core thermocouples and radiation exposure meters (continuous indication at fixed locations) will not be implemented based on direction provided by supplement 1 of NUREG 0737.

19. The isolation condensor system shell-side water level and valve position variables are not applicable to PNPP's design.

20. The Post Accident Sampling System, as designed to Category 3 requirements, will be utilized for this variable.

21. Existing instrumentation (10^{-1}m R/hr to 10^{4}m R/hr) will be utilized for the lower end of the required range. Portable survey instruments (10^{-1} R/hr to 10^{4} R/hr) will be utilized for the entire range specified in Regulatory Guide 1.97.

22. The primary containment isolation valve position variable is covered by both the NSSS and the BOP scope.

23. Suppression pool water temperature has eight sub-channels of temperature individually monitored on each recorder.

24. Area radiation Hi-Range monitors located in the Primary Containment are utilized to meet the requirements of this variable.

25. Each channel monitors the following three plant vents: Turbine Bay/Heater Bay exhaust vent, Off-Gas Building Vent Pipe, and the Main Plant exhaust vent.

26. The drywell spray flow variable is not applicable to PNPP's design.

27. Regulatory Guide 1.97 specifies measurement of the radioactivity of the circulating primary coolant (coolant in active contact with the fuel) as the key variable in monitoring fuel cladding status during isolation of the NSSS. The subject of concern in the Regulatory Guide 1.97 requirement is assumed to be an isolated NSSS. This assumption is justified as current monitors in the condenser off-gas and main steam lines provide reliable and accurate information on the status of fuel cladding when the plant is not isolated. Based on the above, the post-accident sampling system (PASS), designed to Category 3 requirements, will provide an accurate status of coolant radioactivity.

28. Drywell sump equipment and floor drain leakage will be displayed in the control room as a leakage rate instead of level.

29. Instrumentation meeting Category 3 design requirements is considered adequate to monitor water levels above the top of the wide range instruments.

The results of the two analyses are analyzed and compared to establish the actual minimum number and location of LPRMs needed for each APRM channel. A minimum of 14 LPRMs per APRM channel and a minimum of 2 IPRM inputs per level are required to provide adequate protective action.

c. Prudent Operational Limits

Prudent operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious scram is avoided. It is then verified by analysis that the release of radioactive material, following postulated gross failures of the fuel or the reactor coolant pressure boundary, is kept within acceptable bounds. Design basis operational limits are based on operating experience and constrained by the safety design basis and the safety analyses. The selection of tentative scram trip settings has been developed through analytical modeling, experience, historical use of initial setpoints and adoption of new variables and setpoints as experience was gained. The initial setpoint selection method provided for settings which were sufficiently above the normal operating levels (to preclude the possibilities of spurious scrams or difficulties in operation), but low enough to protect the fuel barrier and RCPB. As additional information became available or systems were changed, additional scram variables were provided using the above method for initial setpoint selection. The selected scram settings are analyzed to verify that they are conservative and that the fuel barriers and RCPB are adequately protected. In all cases, the specific scram trip point selected is a conservative value that prevents damage to the fuel or reactor coolant pressure boundary.

d. Margin

The margin between operational limits and the limiting conditions of operation (scram) for the Reactor Protection System are accounted for in technical specifications.

e. Levels

Levels requiring protective action are provided in technical specification.

f. Range of Transient, Steady State, and Environmental Conditions

Environmental conditions for proper operation of the RPS components are discussed in Section 3.11. The RPS power supply range of steady state and transient conditions are provided in Chapter 8.

g. Malfunctions, Accidents, and Other Unusual Events Which Could Cause Damage to Safety Systems

Unusual events are defined as malfunctions, accidents, and others which could cause damage to safety systems. Chapter 15 and Appendix 15A describe the following credible accidents and events; floods, storms, tornados, earthquakes, fires, LOCA, pipe break outside containment, feedwater line break, and missiles. Each of these events is discussed below for the RPS.

All components essential to the operation of the RPS are designed, fabricated, and mounted into appropriate seismically qualified structures. However, even though the sensors initiating reactor scram which monitor turbine stop valve position and turbine control valve fast closure are designed and purchased to Quality Class I, Seismic Class I, they are physically mounted on equipment which is not Seismic Class I/Quality Class I, and are located in the turbine generator building which is not Seismic Class I. For this reason, other diverse variables (reactor pressure and neutron flux trips) can be relied upon for reactor scram if components in the turbine generator building fail.

1. Floods

The buildings containing RPS components have been designed to meet the PMF (Probable Maximum Flood) at the site location. This ensures that the buildings will remain water tight under PMF including wind generated wave action and wave runup.

22. Identification of Protection Systems (IEEE Standard 279, Paragraph 4.22)

The identification scheme for the RPS system is discussed in Section 8.3.1.

7.2.2.3 Conformance to NRC Regulatory Guides

The following is a discussion of conformance to those Regulatory Guides which apply specifically to the RPS. Refer to Section 7.1.2.4 for a discussion of Regulatory Guides which apply equally to all safety related systems.

a. Regulatory Guide 1.22 - Periodic Testing of Protection System Actuation Function

The RPS can be tested during reactor operation by the following separate tests:

The manual scram test. The total test verifies the ability to deenergize the scram pilot valve solenoids without scram by using the manual scram push button switches. By actuating the manual scram switches, the trip logic is deenergized, opening contacts in the trip actuator logic. After the first trip channel is reset, the second trip channel is tripped manually and so forth for the four manual scram switches. In addition to control room annunciator and computer printout indications, scram group indicator lights verify that the trip actuator contacts have opened and interrupted power to the scram solenoids.

The single rod scram test verifies capability of each rod to scram. It is accomplished by operating two toggle switches on the hydraulic control unit for the particular control rod drive. Timing traces can be made for each rod scrammed.

The ADS consists of two redundant and independent trip systems, trip systems A and B. The ADS trip system A actuates the "A" solenoid air pilot valve on each ADS safety relief valve. Similarly, the ADS trip system B actuates the "B" solenoid air pilot valve on each ADS safety relief valve. Actuation of either solenoid pilot valve causes the ADS safety relief valve to open and provide depressurization. To prevent inadvertant actuation of the ADS, two channels of logic for each ADS trip system (A & B) are used. Both channels must be activated to actuate an ADS trip system.

One channel of each trip system includes two differential pressure transmitter inputs monitoring reactor vessel low water level (trip level 3 and trip level 1). The low water level 3 trip provides confirmation of a reactor vessel low water level condition. The second channel is redundant except the low water level confirmation signal is omitted. A manual inhibit switch is provided to allow the operator to prevent automatic ADS initiation.

To assure that adequate makeup water is available after the vessel has been depressurized, each trip channel includes a pump discharge pressure permissive signal indicating LPCI or LPCS system availability for vessel water makeup. Any one of the three LPCI pumps or the LPCS pump available for reactor coolant makeup is sufficient to permit automatic depressurization.

After receipt of the initiation signals and after a delay provided by timers, each of the two solenoid air pilot valves are energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. Each ADS trip system has a time delay that can be reset manually to delay system initiation. The time delay is selected to be within a period that allows the HPCS to perform its function prior to ADS initiation. In the event of HPCS failure, the time delay period is selected to allow initiation of ADS, LPCI and LPCS in time to maintain the fuel barrier temperature within acceptable limits. If reactor vessel water level is restored by HPCS prior to the end of the time delay, ADS initiation will be prevented.

Once initiated, the ADS logic seals-in and can be reset by the control room operator only when vessel water level returns to normal.

Two control switches (one for each trip system solenoid) are located in the control room for each safety/relief valve associated with the ADS. Each switch controls one of the two solenoid pilot valves.

7.3.1.1.1.3 Low Pressure Core Spray (LPCS) - Instrumentation and Controls

a. LPCS Function

The purpose of the LPCS is to provide low pressure reactor vessel core spray following a loss-of-coolant accident when the vessel has been depressurized and vessel water level has not been restored by the HPCS. The LPCS is functionally diverse to the LPCI mode of the Residual Heat Removal System. See Section 6.3.2.

b. LPCS Operation

Schematic arrangements of system mechanical equipment are shown in Figure 6.3-8. LPCS component control logic is shown in Figure 7.3-4. Elementary diagrams are listed in Section 1.7.1. Plant layout drawings are shown in Figure 1.2. Operator information displays are shown in Figure 6.3-8 and Figure 7.3-4.

The LPCS is initiated automatically by either reactor vessel low water level (trip level 1) and/or drywell high pressure. The system is designed to operate automatically for at least 10 minutes without any actions required by the control room operator. Once initiated, the LPCS logic seals-in and can be reset by the control room operator only when the initial conditions return to normal. Refer to Figure 7.3-4 for a schematic representation of the LPCS system initiation logic.

Reactor vessel water level (Trip Level 1) is monitored by two redundant level transmitters. Drywell pressure is monitored by two redundant pressure transmitters. The vessel level trip unit relay contacts and the drywell pressure trip unit relay contacts are connected in a one-out-of-two twice logic arrangement so that no single instrument failure can prevent initiation of LPCS.

The LPCS components respond to an automatic initiation signal simultaneously (or sequentially as noted) as follows:

1. The Division 1 diesel generator is signaled to start.

2. The normally closed test return line to the suppression pool valve MOF012 is signaled closed.

3. When power (offsite or onsite) is available at the LPCS pump motor bus, the LPCS pump is signaled to start.

4. Reactor pressure is monitored by a pressure transmitter which senses pressure on the vessel side of the LPCS injection valve MOF005. When the pressure is low enough to protect the LPCS from overpressure and power is available to the pump motor bus, the injection valve is signaled to open.

   The LPCS pump discharge flow is monitored by a differential pressure transmitter. When the pump is running and discharge flow is low enough to cause pump overheating to occur, the minimum flow return line valve MOF011 is opened. The valve is automatically closed if flow is normal.

   The LPCS pump suction from the suppression pool valve MOF001 is normally open, the control switch is keylocked in the open position, and thus requires no automatic open signal for system initiation.

   The LPCS pump and injection valve are provided with manual override controls. These controls permit the operator to manually control the system subsequent to automatic initiation.

(c) The RHR heat exchanger steam pressure reducing valves AOF051 A, B.

(d) The RHR heat exchanger steam inlet isolation valves MOF052 A, B and MOF087 A, B.

(e) The test return line to the suppression pool valves MOF024 A, B and MOF021.

(f) The containment spray valves MOF028 A, B.

4. Reactor pressure is monitored by pressure transmitters which sense pressure on the vessel side of LPCI injection valves. When the pressure is low enough to protect the LPCI lines from overpressure and power is available to the pump motor buses, the injection valves are signaled to open.

The normally open heat exchanger bypass valves MOF048 A, B are signaled open. The open signal is automatically removed 10 minutes after system initiation to allow the operator to manually control the valve.

Each LPCI pump discharge flow is monitored by a differential pressure transmitter which, when the pump is running and following an 8 second time delay, opens the minimum flow return line valve MOF064 A, B, C if flow is low enough that pump overheating may occur. The valve is automatically closed if flow is normal.

The three RHR pump suction valves from the suppression pool valves MOF004 A and B and F105 have their control switches keylocked in the open position, and thus require no automatic open signal for system initiation. The RHR heat exchanger inlet and outlet valves MOF047 A, B and MOF003 A, B are not part of the LPCI loop and therefore do not require an automatic signal.

b. CRVICS Operation

Schematic mechanical arrangements of containment isolation valves and other components initiated by CRVICS are shown in Figures 5.4-13, 5.1-3, 5.4-16 and 5.4-2. CRVICS component control logic is shown in Figures 7.3-3, 7.3-5 and 7.3-6. Elementary diagrams are listed in Section 1.7.1. Plant layout drawings are shown in Section 1.2. Operator information displays are shown in Figures 5.1-3 and 7.3-3.

During normal plant operation, the isolation control system sensors and trip logic that are essential to safety are energized. When abnormal conditions are sensed, instrument contacts open and deenergize the trip logic and threreby initiate isolation. Once initiated, the CRVICS trip logics seal-in and may be reset by the operator only when the initial conditions return to normal.

Each main steam line isolation valve (MSIV) has two control solenoids. Each solenoid receives inputs from two redundant logics. A signal from either can deenergize the solenoid. For any one valve to close automatically, both of its solenoids must be deenergized.

The main steam line isolation valve logic has a minimum of four redundant instrument channels for each measured variable. One channel of each variable is connected to one trip logic. One group of redundant logics (A, C) is used to control one solenoid of both inboard and outboard valves of all four main steam lines, and the other group of redundant logics (B, D) is used to control the other solenoid of both inboard and outboard valves. The four CRVICS trip logics are arranged in a one-out-of-two twice logic combination (Trip Logic A or C and B or D).

Except for the main steam line drain valves, the remaining containment and vessel isolation valves also operate in pairs. The inboard valves close if both of the Division 2 and 3 logics (B and C) are tripped, and the outboard valves close if the Division 1 and 4 logics (A and D) are tripped.

Main steam line drain outboard valves close if Division 1 (A) isolation logic is tripped, while an inboard valve closes if the Division 2 logic (B) is tripped.

The following variables provide inputs to the CRVICS logics for initiation of reactor vessel and containment isolation, as well as the initiation or trip of other plant functions when predetermined limits are exceeded. Combinations of these variables, as necessary, provide initiation of various isolating and initiating functions as described in Table 6.2-32 and below:

1. Reactor Vessel Low Water Level

A low water level in the reactor vessel could indicate that reactor coolant is being lost through a breach in the reactor coolant pressure boundary and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes.

Reactor vessel low water level initiates closure of various valves. The closure of these valves is intended to isolate a breach of the pipelines, conserve reactor coolant by closing off process lines, and limit the escape of radioactive materials from the containment through process lines that communicate with the primary coolant boundary or containment.

Reactor vessel water level is monitored by four redundant level transmitters. Each instrument provides a low water level input to one of the four CRVICS trip channels.

Three reactor vessel low water level isolation trip settings are used to complete the isolation of the containment and the reactor vessels. The first (and highest) level 3 reactor vessel low water level isolation trip setting initiates closure of RHR isolation valves, the second reactor vessel low water level (level 2) initiates closure of all valves in major process pipeline except the main steam lines, and drains the nuclear closed cooling system isolation valves and the instrument air system isolation valves for the MSIVs air supply. The main steam lines are left open to allow the removal of heat from the reactor core. The third, and lowest

(level 1) reactor vessel low water level, completes the isolation of the containment and pressure vessel by initiating closure of the main steam line isolation valves, main steam line drain valves, nuclear closed cooling system isolation valves and the instrument air system isolation valves for the MSIVs air supply.

When a decrease in main steam line pressure below a preselected value is detected, the CRVICS initiates closure of all main steam line isolation and drain valves.

The main steam line low pressure trip is bypassed by the reactor mode switch in the Shutdown, Refuel, and Startup modes of reactor operation. In the Run mode, the low pressure trip function is operative.

7. Containment and Drywell Ventilation Exhaust Radiation Monitor - Instrumentation and Controls

The Containment and Drywell Ventilation Exhaust Radiation monitor consists of four sensor and trip units. Each channel has two trips. The upscale trip indicates high radiation and the downscale trip indicates instrument trouble.

The Containment and Drywell Ventilation Exhaust Radiation Monitor senses reactor building exhaust to the elevated release point. In the event that radiation levels exceed predetermined limits, the containment and drywell purge system inboard and outboard isolation valves are closed.

8. Reactor Water Cleanup (RWCU) System-High Differential Flow

High differential flow in the Reactor Water Cleanup System could indicate a breach of the system pressure boundary of the cleanup system. The flow at the inlet to the system (suction from Recirc. lines) is compared with the flow at the outlets of the system (flow return to feedwater or flow to the main condenser and/or radwaste).

Two redundant differential flow sensors compare the Reactor Water Cleanup System inlet-outlet flow. Each of the flow monitoring sensors provides an input to one of the two (inboard or outboard) logic trip channels.

The output trip signal of each sensor initiates a channel trip and closure of either the inboard or outboard Reactor Water Cleanup System isolation valve.

Diversity of trip initiation signals for temperature is provided by two ambient temperature elements and two differential temperature elements and associated temperature switches (TS and dTS) for each Reactor Water Cleanup System area. One differential temperature element and its differential temperature switch and an ambient temperature element and its temperature switch in an RWCU area are associated with one of two logic channels.

The RWCU isolation signals can be bypassed manually from the control room by actuating a keylocked switch.

10. RHR System-Area High Ambient Temperature and Differential Temperature

High temperature in the equipment room areas of the RHR system could indicate a breach in the reactor coolant pressure boundary in the RHR system.

Two redundant ambient temperature and two redundant differential temperature sensors are located in each (2) RHR equipment area. An ambient and differential temperature sensor in each equipment area are associated with one trip logic, channel A. The remaining temperature sensors in the equipment areas are associated with another trip logic, channel B.

When an increase in RHR system area ambient temperature or differential temperature is detected, the CRVICS initiates closure of RHR system shutdown cooling isolation valves, RHR containment isolation valves, and RCIC steam supply isolation valves.

The output trip signal of each sensor initiates a channel trip and closure of either the inboard or outboard RHR system isolation valve. Both trip channels must trip to close both the inboard and outboard isolation valves.

Diversity of trip initiation signals for RHR line break is provided by ambient temperature and differential temperature. An increase in space temperature or differential temperature will initiate RHR system isolation.

11. High Temperature at the Outlet of the RWCU Non Regenerative Heat Exchanger

A high temperature signal for coolant at the discharge of the non regenerative heat exchanger indicates the potential for damage to the filter/demineralizer resins.

A temperature controller monitors non regenerative heat exchanger temperature and provides an output signal to a CRVICS trip channel for closing outboard RWCU isolation valve G33-F004.

12. SLCS Actuation

Based on the need to prevent removal of the sodium pentaborate solution from the vessel after SLCS injection, RWCU isolation valves G33-F001 and G33-F004 are actuated closed by the CRVICS logic on inputs from SLCS pump A and pump B actuation respectively.

13. Reactor Vessel Pressure

Operation of the RHR system at a high reactor vessel pressure could result in exceeding the design pressure of the system resulting in damage to piping and components and loss of reactor coolant.

Reactor vessel pressure is monitored by four redundant pressure transmitters. Each transmitter trip unit provides an input to one of the four trip channels.

14. Main Condenser Vacuum Trip

The main turbine condenser low vacuum signal could indicate a leak in the condenser. Initiation of automatic closure of various valves will prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material.

Four redundant pressure transmitters monitor the main condenser vacuum. The output trip signal of each instrument channel initiates a channel trip. The output trip signal of the channel logics are combined in one-out-of-two twice logic for MSIVs and one-out-of-one logic for drain valves.

When a significant decrease in main condenser vacuum is detected, the CRVICS initiates closure of all main steam line isolation and drain valves.

Main condenser low vacuum trip can be bypassed manually from the control room by actuating a keylocked switch.

7.3.1.1.3 Main Steamline Isolation Valve Leakage Control System (MSIV-LCS) - Instrumentation and Control

a. MSIV-LCS Function

The MSIV-LCS is designed to minimize the release of fission products which could leak through the closed MSIV's and bypass the AEGTS after the postulated LOCA. This is accomplished by directing the leakage through the closed MSIVs to bleed lines which pass the leakage flow into an area served by the AEGTS.

b. MSIV-LCS Operation

Schematic arrangements of system mechanical equipment is shown in Figures 6.7-1 and 6.7-2. MSIV-LCS system component control logic is shown in Figure 7.3-7. Elementary diagrams are listed in Section 1.7.1. Plant layout drawings are shown in Section 1.2. Operator information displays are shown in Figure 6.7-1 and Figure 7.3-7.

The MSIV-LCS is manually actuated after a LOCA has occurred, provided that the reactor and steamline pressures are below the pressure permissive set points and the inboard MSIVs are fully closed. The outboard and inboard subsystems are provided with one remote manual initiating switch each.

When the inboard system is initiated, the exhaust blower C001 is actuated and the bleed valves MOF001A, E, J, N and MOF002A, E, J, N and the bypass valves MOF003A, E, J, N are opened, heaters are actuated and timers are initiated. If the steamline pressure is greater than 5 psig after one minute, the bleed valves will close. If the pressure is not excessive, the bleed valves will remain open. After another 1 minute, the bypass valve is closed. The flow is thus routed through the flow element. After another 11 minutes, a third timer allows flow to be monitored and the bleed valves to be closed, if necessary, for high flow.

When the outboard system is initiated, depressurization valves MOF006, 7, 8 and 9 are opened and the exhaust blower C002 is activated. When the steam lines have depressurized to approximately atmospheric pressure, the depressurization branch valves MOF008 and MOF009 are closed and flow is diverted to the blower suction.

7.3.1.1.4 RHRS-Containment Spray Cooling Mode (RCSCM) - Instrumentation and Controls

a. Containment Spray Cooling Mode Function

The containment spray cooling mode is an operating mode of the RHR system. It is designed to provide the capability of condensing steam in the containment atmosphere and reducing the suppression pool temperature. The system is automatically or manually initiated when necessary.

b. Containment Spray Cooling Mode Operation

Schematic arrangements of system mechanical equipment is shown in Figure 5.4-13. RHR system component control logic is shown in Figure 7.3-5. Elementary diagrams are listed in Section 1.7.1. Plant layout drawings are shown in Section 1.2. Operator information displays are shown in Figures 5.4-13 and 7.3-5.

The Containment Spray Cooling Mode is initiated automatically or manually. LPCI flow is diverted to the containment by opening valves MOF028A and B, and closing MOF042A, B, MOF048A, B, MOF024A and B.

The following conditions must exist before containment spray can be initiated automatically:

1. The LOCA signal which automatically initiated LPCI must still exist.

2. Drywell high pressure is monitored by two redundant pressure transmitters. One of the two transmitters must indicate high pressure.

3. The containment pressure must equal or exceed 9 psig.

4. A 10-minute delay after LOCA is detected.

7.3.1.1.5 RHRS Suppression Pool Cooling Mode (RSPCM) - Instrumentation and Controls

a. RHRS-SPCM Function

The suppression pool cooling mode is an operating mode of the Residual Heat Removal System. It is designed to prevent suppression pool temperature from exceeding predetermined limits following a reactor blowdown of the ADS or safety relief valves.

b. SPCM Operation

Schematic arrangements of system mechanical equipment is shown in Figure 5.4-13. Component control logic is shown in Figure 7.3-5. Plant layout drawings and elementary diagrams are identified in Section 1.7.1. Operator information displays are shown in Figures 5.4-13 and 7.3-5.

The suppression pool cooling mode is initiated by the control room operator either during normal plant operation or following a LOCA, when the containment atmosphere monitoring system (see Section 7.6.1.8) indicates that suppression pool temperature may exceed a predetermined limit.

During normal plant operation, the operator initiates the SPCM as follows:

1. The RHR Pump (A or B) is started. The Emergency Service Water Pump is started and the RHR heat exchanger service water discharge valve is opened.

2. The RHR test return line valve MOF024 A, B is opened.

3. The RHR heat exchanger inlet and outlet valves MOF047 A, B and MOF003A, B are open. The heat exchanger bypass valve MOF048 A, B and valve MOF024 A, B are throttled as necessary.

responses from the system to ensure the continued habitability of the control complex. The instrumentation and controls for this system are shown on Figures 6.4-1, 9.4-1 and 9.4-20.

The Control Complex HVAC System consists of two subsystems:

1. Control room HVAC system
2. Control complex chilled water system

b. System Operation

The control room HVAC system consists of two independent control loops; the power for each loop is supplied from the Class 1E electrical system.

The control room HVAC system is normally manually initiated. Changeover to the emergency recirculation mode is manually or automatically initiated by high drywell pressure, low reactor water level, high radiation signal from the system radiation monitor, or by detection of high toxic gas concentrations. Changeover to the smoke clear mode is manually initiated.

Status lights on the control panel indicate that the motor driven fans are energized. All dampers are provided with limit switches to provide indication of their opened or closed position on the control panel. During emergency recirculation mode of operation, one or both of the fans operate continuously.

The instrumentation and controls for the control complex chilled water system are shown in Figure 9.4-20.

The control complex chilled water system has two loops. Loop A provides chilled water to the control room cooling coil A and motor control center area and miscellaneous areas cooling coil A. Loop B provides chilled water to the control room cooling coil B and the motor control center area and miscellaneous areas cooling coil B. The two loops are served by three 100 percent capacity circulating pumps and three 100 percent capacity chillers.

switches permit operation of the ventilation systems independently of the diesel generators for testing or other purposes.

The indications and alarms provided in the control room allow the operator to monitor and control the operation of each system. The redundant supply fans in each diesel generator room permit maintenance and testing without affecting diesel generator availability.

7.3.1.1.9 Containment Cooling and Purification System - Instrumentation and Controls

The containment temperature and pressure, especially in the drywell, will vary depending upon the liquid and steam leakage rates and the particular containment configuration. Thus, the function of the system is to control the containment environment during normal operation so as to ensure operability of the equipment therein and to provide the accessibility and conditional habitability of the unit. The system uses the necessary instrumentation and controls to regulate the atmospheric conditions for normal operational and for postulated abnormal conditions as described in Section 6.2.3.

The containment cooling and purification system encompasses the ventilation, cooling, heating and purge systems for the containment vessel, drywell and annulus and is described in the following systems and subsystems.

a. Drywell cooling systems.
b. Containment vessel cooling system.
c. Containment vessel and drywell purge system.
d. Annulus exhaust gas treatment system.

There are no safety related functions performed by the drywell cooling and containment vessel cooling systems. The containment cooling and purification system containment isolation valves instrumentation and controls are discussed in Section 7.3.1.1.2.

7.3.1.2 Design Basis

The ESF systems are designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the reactor coolant pressure boundary. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier and reactor coolant pressure boundary. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are identified, are presented in that chapter.

a. Variables Monitored to Provide Protective Action

The following variables are monitored in order to provide protective actions to the ESF systems:

1. HPCS

(a) Reactor Vessel Low Water Level (Trip Level 2)
(b) Drywell High Pressure

2. ADS

(a) Reactor Vessel Low Water Level (Trip Level 3)
(b) Reactor Vessel Low Water Level (Trip Level 1)

(3) LPCS and LPCI

(a) Reactor Vessel Low Water Level (Trip Level 1)
(b) Drywell High Pressure

4. CRVICS

(a) Reactor Vessel Low Water Level (Trip Level 3)
(b) Reactor Vessel Low Water Level (Trip Level 2)
(c) Reactor Vessel Low Water Level (Trip Level 1)

(d) Main Steam Line High Radiation

(e) Main Steam Line Area High Ambient and Differential Temperature

(f) Main Steam Line High Flow

(g) Turbine Inlet Low Steam Pressure

(h) Containment and Drywell Ventilation Exhaust High Radiation

(i) RWCU High Differential Flow

(j) RWCU Area High Ambient Temperature and Differential Temperature

(k) RHR Area High Ambient Temperature and Differential Temperature

(l) Main Condenser Low Vacuum

(m) High Drywell Pressure

(n) RWCU Heat Exchanger Outlet High Temperature

(o) SLCS Actuation

(p) Reactor Vessel Pressure

5. MSIV-LCS

(a) Reactor Vessel Low Pressure

(b) Steamline Low Pressure

6. RHRS-CSCM

(a) Drywell High Pressure

(b) Reactor Vessel Water Level (Trip Level 1)

(c) Containment High Pressure

7. RHRS-SPCM

(a) Suppression Pool Temperature

(b) Drywell High Pressure

(c) Reactor Vessel Low Water Level (Trip Level 1)

8. Emergency Water Systems: ESW and ECC

   (a) RHR, LPCS, RCIC, or Diesel Generator Start
   (b) HPCS Start (just Loop "C" of ESW is needed)

9. Containment Combustible Gas Control System

   (a) Containment hydrogen concentration

10. Standby Power Systems

(a) HPCS and Standard Diesel Generator Systems

(1) Refer to Section 8.3.2

(b) Diesel Generator Support Systems

(1) Fuel Oil Day Tank Level
(2) Fuel Oil Main Storage Tank Level
(3) Starting Air Receiver Pressure
(4) Standby or HPCS Diesel Start

11. Containment Cooling and Purification System

(a) Reactor Vessel Low Water Level (Trip Level 2)
(b) Drywell High Pressure
(c) Containment and Drywell Ventilation Exhaust High Radiation
(d) Annulus to Outside Air Differential (AEGTS only)
(e) Low Flow (Fan Failure) on the Operating Train (AEGTS only)

12. Suppression Pool Makeup System

(a) Reactor Vessel Low Water Level (Trip Level 1)
(b) Drywell High Pressure
(c) Suppression Pool Low-Low Level

13. Containment Vacuum Relief System

(a) Reactor Vessel Low Water Level (Trip Level 2)
(b) High Drywell Pressure
(c) Low Containment to Outside Air Differential Pressure

14. Drywell Vacuum Relief System

(a) Reactor Vessel Low Water Level (Trip Level 1)
(b) High Drywell Pressure
(c) Low Drywell to Containment Differential Pressure

15. ESF Building and Area HVAC System

(a) Reactor Vessel Low Water Level (Trip Level 1)

(b) High Drywell Pressure

(c) Diesel Generator Star Signals (Diesel Generator Building Ventilation System only)

16. Pump Room Cooling Systems

(a) ECCS Pump Motor Running
(b) RCIC Steam Admission Valve Open. (RCIC Pump Room only)

17. Control Complex HVAC

(a) Reactor Vessel Low Water Level (Trip Level 1)
(b) Drywell High Pressure
(c) High Radiation
(d) Toxic Gas (Chlorine or Ethylene Oxide)
(e) Loss of Off-Site Power

The plant conditions which require protective action involving the ESF systems are described in Chapter 15 and Appendix 15A.

b. Location and Minimum Number of Sensors

Where applicable in technical specifications, the minimum number of sensors is specified to monitor safety-related variables. There are no sensors in the ESF systems which have a spatial dependence.

c. Prudent Operational Limits

Operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious ESF system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

d. Margin

The margin between operational limits and the limiting conditions of operation of ESF systems are accounted for in technical specifications.

e. Levels

Levels requiring protective action are established in technical specifications.

f. Range of Transient, Steady State, and Environmental Conditions

Environmental conditions for proper operation of the ESF components are discussed in Section 3.11.

g. Malfunctions, Accidents, and Other Unusual Events Which Could Cause Damage to Safety System

Chapter 15 describes the following credible accidents and events: floods, storms, tornados, earthquakes, fires, LOCA, pipe break outside containment. Each of these events is discussed below for the ESF systems.

1. Floods

The buildings containing ESF systems components have been designed to meet the PMF (Probable Maximum Flood) at the site location. This

E12-F006B: Motor operated valve (shutdown cooling)

E12-F008: Motor operated valve (outboard shutdown isolation)

E12-F009: Motor operated valve (inboard suction isolation)

E12-F011A: Motor operated valve (RHR heat exchanger flow to suppression pool)

E12-F023: Motor operated valve (reactor head spray)

E12-F024A: Motor operated valve (RHR test line)

E12-F026A: Motor operated valve (RHR heat exchanger flow to RCIC)

E12-F027A: Motor operated valve (injection shutoff)

E12-F028A: Motor operated valve (containment spray)

E12-F037A: Motor operated valve (shutoff upper pool cooling)

E12-F042A: Motor operated valve (RHR injection)

E12-F047A: Motor operated valve (heat exchanger shell side inlet)

E12-F048A: Motor operated valve (heat exchanger shell side bypass)

E12-F040: Motor operated valve (discharge to radwaste)

E12-F052A: Motor operated valve (steam line isolation)

E12-F053A: Motor operated valve (RHR injection)

E12-F064A: Motor operated valve (RHR pump minimum flow)

The following RHR system loop B equipment/functions have control switches located at their respective motor control centers or switchgear panels:

E12-C002B: Residual heat removal pump

E12-F003B: Motor operated valve (heat exchanger shell side outlet)

E12-F004B: Motor operated valve (RHR pump suction)

E12-F011B: Motor operated valve (RHR heat exchanger flow to suppression pool)

E12-F024B: Motor operated valve (RHR test line)

E12-F026B: Motor operated valve (RHR heat exchanger flow to RCIC)

E12-F027B: Motor operated valve (injection shutoff)

E12-F028B: Motor operated valve (containment spray)

E12-F037B: Motor operated valve (shutoff upper pool cooling)

E12-F042B: Motor operated valve (RHR injection)

E12-F047B: Motor operated valve (heat exchanger shell side inlet)

E12-F006B: Motor operated valve (shutdown cooling)

E12-F048B: Motor operated valve (heat exchanger shell side bypass)
E12-F052B: Motor operated valve (steam line isolation)
E12-F053B: Motor operated valve (RHR injection)
E12-F064B: Motor operated valve (RHR pump minimum flow)

See Figure 5.4-13.

The following RHR instrumentation is located on the Division 1 remote shutdown control panel:

C61-R005: RHR flow indicator for loop A

The following RHR instrumentation is located on the Division 2 remote shutdown indicating panel:

C61-R025: RHR flow indicator for loop B.

Valve position status indication and pump status indication.

Nuclear Boiler System

The following functions have transfer and control switches located at the Division 1 remote shutdown control panel and control switches at the Division 2 remote shutdown control panel:

B21-F051C: Air operated safety relief valve
B21-F051G: Air operated safety relief valve
B21-F051D: Air operated safety relief valve

Emergency Closed Cooling System

The following loop A emergency closed cooling system equipment has transfer and control switches located at the Division 1 remote shutdown control panel:

P42-C001A: Emergency closed cooling pump A

The following loop B emergency closed cooling system has control switches located on the associated switchgear panel in the Division 2 switchgear room:

P42-C001B: Emergency closed cooling pump B

See Figure 9.2-3.

The following emergency closed cooling system instrumentation is provided on the Division 1 remote shutdown control panel:

P42-R045A: Flow indicator (ECCS heat exchanger A)

The following emergency closed cooling system instrumentation is provided on the Division 2 remote shutdown control panel:

P42-R045B: Flow indicator (ECCS heat exchanger B)

The following instrument 120 VAC power systems have a transfer switch located at the Division 1 remote shutdown panel:

R41-K050: 120 VAC instrument power

Pump status indicators.

a. Variables monitored to provide protective actions

RCIC - Reactor vessel low water level (trip level 2) is monitored in order to provide protective actions to the safe shutdown systems. All other safe shutdown systems are initiated by operator actions.

The plant conditions which require protective action involving safe shutdown are described in Chapter 15 and Appendix 15A.

b. Location and Minimum Number of Sensors

Technical specifications will discuss the minimum number of sensors required to monitor safety related variables. There are no sensors in the safe shutdown systems which have a spatial dependence.

c. Prudent Operational Limits

Prudent operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious safe shutdown system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

d. Margin

The margin between operational limits and the limiting conditions of operation of safe shutdown systems are accounted for in technical specifications.

e. Levels

Levels requiring protective action are established in technical specifications.

7. Control and Protection Interaction (IEEE Standard 279, Paragraph 4.7).

The RCIC and SLCS systems have no interaction with plant control systems.

8. Derivation of System Inputs (IEEE Standard 279, Paragraph 4.8).

All inputs to the RCIC system that are essential to its operation are direct measures of appropriate variables.

Display instrumentation in the control room provides the operator with directly measured information on reactor vessel water level, pressure, neutron flux level and control rod position. Based on this information the operator can assess the need for SLCS.

9. Capability for Sensor Checks (IEEE Standard 279, Paragraph 4.9).

Refer to Section 7.4.2.3, Regulatory Guide 1.22.

10. Capability for Test and Calibration (IEEE Standard 279, Paragraph 4.10).

Refer to Section 7.4.2.3, Regulatory Guide 1.22.

11. Channel Bypass or Removal from Operation (IEEE Standard 279-1971, Paragraph 4.11).

Calibration of a sensor which introduces a single instrument channel trip will not cause a protective action without the coincident trip of a second channel. Removal of a sensor from operation during calibration does not prevent the redundant instrument channel from functioning.

The discharge pumps for SLCS are redundant, so that one may be removed from service during normal plant operation.

The DBA-LOCA serves as the envelope accident sequence event to provide and demonstrate the plant's post-accident tracking capabilities. All other accidents have less severe and limiting tracking requirements.

The following process instrumentation provides information to the operator after a DBA-LOCA to monitor reactor conditions.

The plant protection/ESF system electronic trip system (Section 7.1.3) provides continuous control room indication of each variable monitored by the RPS, ECCS, CRVICS and RCIC. Each variable is sensed by an analog transmitter that continuously transmits a signal proportional to the variable range, to a trip unit located in the control room. A milliammeter located on each trip unit displays the transmitted signal. The ammeter allows visual cross-checking between instrument channels to verify operability and variable level.

7.5.1.4.2.1 Reactor Water Level

Three wide range water level signals are transmitted from three independent differential pressure transmitters and are recorded on three, two-pen recorders. For two of the recorders, one pen records the wide range level and the other pen records the reactor pressure as stated in Section 7.5.1.4.2.2. For the third recorder, again one pen records the wide range level and the other pen records the fuel zone level as stated in Table 7.1-4. The range of the recorded level is from the top of the feedwater control range (above the high level turbine trip point) down to a point near the top of the active fuel.

positive differential and high negative differential pressure. Drywell pressure narrow range and wide range measurements are recorded in the control room and the narrow range measurement is indicated and annunciated in the control room.

Containment pressure is also measured with redundant channels, with each channel being indicated, recorded, and annunciated in the control room. Additional redundant channels of instruments are used for extended range measurement of containment pressure with the signals recorded in the control room.

b. Drywell and Containment Temperature Monitoring

Temperature signals from sensors located in the drywell and the containment are recorded in the control room. A common alarm for high drywell temperature and a common alarm for high containment temperature for each channel are annunciated in the control room. One temperature sensor from each channel in the drywell and the containment has its signal indicated in the control room.

c. Suppression Pool Temperature Monitoring

Each channel of the suppression pool temperature sensors transmits the sensors' signals to temperature switches and then to two and four position selector switches located on the post accident monitoring panel A suppression pool temperature is selected and indicated on a single indicator located on the ECCS benchboard. A common alarm for each channel on high suppression pool temperature is annunciated in the control room. Each channel is recorded in the control room.

d. Suppression Pool Water Level

There are two redundant sets of three suppression pool level transmitters and three instrumentation channels. Two channels of each set are narrow and extended wide range. The third channel of each set provides indication of containment water level above the 641 foot elevation. Each channel is indicated in the control room.

be operable during and after a LOCA in conjunction with a SSE. Power is from independent instrument buses supplied from the two divisional a-c buses. This instrumentation complies with the independence and redundancy requirements of IEEE Standard 279 and provides recorded outputs.

The sensors and recorders are designed to operate during normal operation and/or post-accident environmental conditions. The design criteria that the instruments must meet are discussed in Section 7.1.2. There are two complete and independent channels of wide range reactor water level and reactor vessel pressure with a channel of each parameter having its readout on a separate two-pen recorder in the control room. A third independent channel of wide range reactor water level is provided with indication on a two-pen recorder in the control room shared with a fuel zone reactor water level channel.

The design, considering the accuracy, range and quality of the instrumentation, is adequate to provide the operator with accurate reactor water level and reactor pressure information during normal operation, abnormal, transient, and accident conditions.

b. Suppression Pool Water Level and Temperature

This instrumentation complies with the requirements of IEEE Standard 279 and provides recorded outputs. All equipment except the recorders and indicators will perform its required function during and after the seismic event. Recorders and instrumentation perform their required function after the seismic event; however, pen or pointer flutter is expected to occur during the event.

c. Drywell and Containment Pressure and Temperature

This instrumentation is redundant, electrically independent, and is qualified to be operable during and after a LOCA. Power is from independent buses and the instrumentation complies with the requirements of IEEE Standard 279 and provides recorded outputs. All equipment except the

TABLE 7.5-1

SAFETY RELATED DISPLAY INSTRUMENTATION (DISPLAY INSTRUMENTATION FOR SAFETY-RELATED SYSTEMS)

System	Parameter	Type of Readout	Number of Channels	Range	Readout Location
Rod Control and Information	Control Rod Position	Lights	2 per rod	N/A	CR
	Control Rod Scram Valves	Lights	1 per valve	N/A	CR
Neutron Monitoring	Power Range Neutron Flux	Recorder	8 (2 per recorder)	0 to 125%	CR
	Source Range Count Rate	Recorder	4 (2 per recorder)	10^{-1} to 10^{6} CPS	CR
Nuclear Boiler	Reactor Vessel Pressure	Recorder	2	0 to 1500 psig	CR
	Reactor Vessel Water Level: Wide Range	Recorder	3	5" to 230"	CR
	Fuel Zone	One recorder, two meters	3	-150" to 50"	CR
	Relief Valve Initiation Circuit	Lights	2	N/A	CR
RCIC	RCIC Flow	Meter	1	0 to 800 gpm	CR
	RCIC Isolation Valve	Lights	2	N/A	CR
	RCIC Discharge Pressure	Meter	1	0 to 1500 psig	CR
	Relief Valve Discharge Pipe Temperature	Recorder	1	0 to 600° F	CR
Emergency Core Cooling	HPCS Flow	Meter	1	0 to 10,000 gpm	CR
	HPCS Discharge Pressure	Meter	1	0 to 1500 psig	CR
	LPCS Flow	Meter	1	0 to 10,000 gpm	CR
	RHR Flow (LPCI and Shutdown Cooling)	Meter	1 per loop	0 to 10,000 gpm	CR
	RHR Service Water Flow	Meter	1 per loop	0 to 10,000 gpm	CR
	ECCS Pumps	Status Lights	1 set per pump	N/A	CR
	ECCS Valves	Position Lights	1 set per valve	N/A	CR

TABLE 7.5-1 (Continued)

System	Parameter	Type of Readout	Number of Channels	Range	Readout Location	
MSIVLC	MSIVLC Steam Line Pressure (Low)	Meter	1	30" Hg to 10 psig	CR	
	MSIVLC Steam Line Pressure (High)	Meter	1	0 to 100 psig	CR	
	MSIV Leakage Control System Flow	Meter	1 per MSIV Line	0 to 100 scfh	CR	
Containment Drywell Monitoring	Drywell Pressure (Wide)	Recorder	2	30" Hg to 35 psig	CR	
	Drywell Pressure (Narrow)	Recorder/Meter	2	10" Hg to +5 psig	CR	
	Containment Pressure (Wide)	Recorder	2	10" Hg to 60 psig	CR	
	Containment Pressure (Normal)	Recorder/Meter	2	10" Hg to 20 psig	CR	
	Containment/Drywell Differential Pressure	Meter	2	-2.5 to +2.5 psig	CR	
	Drywell Temperature	Recorder	2/(3 locations each)	40 to 440° F	CR	
	Drywell Temperature	Meter	2	40 to 440° F	CR	
	Containment Temperature	Recorder	2/(4 locations each)	50 to 200° F	CR	
	Containment Temperature	Meter	2	50 to 200° F	CR	
	Suppression Pool Level (Narrow)	Recorder/Meter	2	16 to 19 feet	CR	
	Suppression Pool Level (Extended Wide)	Recorder	2	2 to 24 feet	CR	
	Containment Water Level	Recorder	2	16 to 96 feet	CR	
	Suppression Pool Temperature	Recorder/ Meter	2/(8 locations each)	30 to 230° F	CR	NOTE: Single meter selectable on one of 8 locations
	Isolation Valves	Position Lights	1 set per valve	N/A	CR	

TABLE 7.5-1 (Continued)

System	Parameter	Type of Readout	Number of Channels	Range	Readout Location
Emergency Water (Emergency Service Water, (ESW); Emergency Closed Cooling Water (ECCW))	ESW Loop Inlet Temperature	Meter	1 each loop	0 to 100° F	CR
	ESW Loop Pressure	Meter	1 each loop	0 to 160 psig	CR
	ESW Flow to HPCS Diesel Hex	Meter	1 each loop	0 to 1000 gpm	CR
	ESW Flow to Stby Diesel Hex	Meter	1 each loop	0 to 1200 gpm	CR

TABLE 7.5-1 (Continued)

System	Parameter	Type of Readout	Number of Channels	Range	Readout Location
Emergency Water (Emergency Service Water, (ESW); Emergency Closed Cooling, (ECCW)) (Cont'd)	ESW Flow to ECCS Hex	Meter	1 each loop	0 to 3000 gpm	CR
	ESW Flow to RHR Hex	Meter	1 each loop	0 to 8000 gpm	CR
	ECCW Loop Pressure	Meter	1 each loop	0 to 160 psig	CR
	ECCW Loop Flow	Meter	1 each loop	0 to 2600 gpm	CR
	ECCW Loop Temperature	Meter	1 each loop	50 to 150° F	CR
	ESW Pumps	Status Lights	1 set per pump	N/A	CR
	ESW Valves	Position Lights	1 set per valve	N/A	CR
	ECCW Pumps	Status Lights	1 per pump	N/A	CR
	ECCW Valves	Position Lights	1 set per valve	N/A	CR
Standby Diesel Generator	Generator Field Current	Meter	1 each generator	0-300 Amps	CR
	Generator Field Voltage	Meter	1 each generator	0-300 Volts	CR
	Generator Reactive Power	Meter	1 each generator	0-6000 kVAR	CR
	Generator Power	Meter	1 each generator	0-8000 kW	CR
	Generator Current	Meter	1 each generator	0-1200 Amps	CR
	Generator Voltage	Meter	1 each generator	0-5250 Volts	CR
	Diesel Generator Engine Speed	Meter	1 each generator	0-600 rpm	CR
	Generator Synchroscope	Meter	1 each generator	Slow-Fast	CR
	Standby Power Sources (Voltage/Current/Circuit Breaker Position)	Meter/ Status Lights	1 per source	Various and N/A	CR

TABLE 7.5-1 (Continued)

System	Parameter	Type of Readout	Number of Channels	Range	Readout Location
Emergency and Standby Diesel Generator	Diesel Fuel Storage Tank Level	Meter	1 each generator	0 to 100% level	CR
Support Systems	Diesel Fuel Day Tank Level	Meter	1 each generator	0 to 555 gal. (HPCS gen.) 0 to 550 gal. (Standby gen.)	CR
	Ventilation Fan	Status Lights	1 set per fan	N/A	CR
	Ventilation Outside Air Damper	Position Lights	1 set per damper	N/A	CR
Combustible Gas Control	Hydrogen Concentration	Recorder	2/(4 locations each)	0 to 30% H_2	CR
	Drywell Purge Compressor	Status Lights	1 set per compressor	N/A	CR
	Drywell Purge Valves	Position Lights	1 set per valve	N/A	CR
	Hydrogen Recombiner Temperature	Meter	-	-	-
	Hydrogen Recombiner Power	Meter	-	-	-
	Hydrogen Recombiner	Status Lights	1 set per recombiner	N/A	CR
	Backup Purge Valve	Position Lights	1 set per valve	N/A	CR
Annulus Exhaust Gas Treatment	Annulus/Outside Atmosphere Differential Pressure	Recorder	2	0 to 5" H_2O Vacuum	CR
	AEGTS Fans	Status Lights	1 set per fan	N/A	CR
	AEGTS Dampers	Position Lights	1 set per fan	N/A	CR

The following is a description of each RCIC leak detection method:

a. RCIC Area Temperature Monitoring

High temperature in the RCIC equipment area could indicate a breach in the RCIC steam line reactor coolant pressure boundary.

Two redundant ambient area and differential temperature monitoring channels are provided. Each redundant instrument provides input to one of two logic channels (ESF Division 1 or 2).

Using 1 out of 2 logic for a division, an RCIC equipment area high area ambient or high differential temperature initiates an isolation of either the RCIC system inboard or outboard isolation valves.

A bypass/test switch is provided in each logic channel for the purpose of testing the temperature monitor without initiating RCIC system isolation.

Diversity is provided by RCIC steam line flow and pressure monitoring.

b. RCIC Flow Rate Monitoring

The steam line flow rate from the reactor vessel leading to the RCIC turbine is monitored by four differential pressure transmitters. During high flow conditions, the flow rate trip unit initiates the auto-isolation signal. A time delay in each logic division prevents inadvertent system isolations due to pressure spikes. See Section 7.4.1.

High flow in the steam line initiates isolation of the RCIC system.

Diversity is provided by ambient temperature, differential temperature and RCIC steam line pressure monitoring.

c. RCIC Pressure Monitoring

The steam line pressure from the reactor vessel leading to the RCIC turbine is monitored by two pressure transmitters. In the presence of a leak, resulting in low line pressure, the RCIC pressure trip unit initiates the auto-isolation signal. See Section 7.4.1.

Diversity is provided by ambient temperature, differential temperature and RCIC steam line flow monitoring.

Outputs from the two monitoring circuits are used to generate the RCIC auto-isolation signals (one for each division) to isolate the inboard and outboard isolation valves.

d. Main Steam Line Tunnel Area Temperature Monitoring

High temperature in the MSL tunnel could indicate a breach in the reactor coolant pressure boundary.

Two redundant MSL ambient temperature and Δ temperature monitoring channels are provided. Each redundant instrument provides input to one of two logic channels (Div. 1 or 2).

Using 1 out of 2 logic for a division, a MSL tunnel high area ambient or high differential temperature initiates an isolation of either the RCIC inboard or outboard isolation valves.

e. High Temperature in the RHR Equipment Areas could indicate a breach in the reactor coolant pressure boundary.

Two redundant ambient temperature and Δ temperature monitoring channels are provided for each of two RHR equipment areas. Each redundant instrument provides input to one of two logic channels (Div. 1 or 2). Any high RHR equipment area ambient temperature or differential temperature for a division will initiate isolation of either the inboard or outboard RCIC isolation valves.

7.6.1.3.3 RHR System Leak Detection

The steam line to the RHR heat exchangers is monitored for leaks by the leak detection system. Leaks from the RHR system are detected by equipment area ambient and differential temperature monitoring, and by steam line flow rate

in the common RHR/RCIC steam line. If the monitored parameters indicate that a leak exists, the LDS initiates an RHR isolation signal.

Outputs from both circuits are used to generate the RHR auto-isolation signal (one for each division) to isolate the inboard and outboard isolation valves.

The following is a description of each RHR leak detection method:

a. RHR Area Temperature Monitoring

The RHR area temperature monitoring circuit is identical to the one described for the RCIC leak detection method (see Section 7.6.1.3.2.f).

Two redundant ambient and differential temperature monitoring channels are provided for each of two RHR equipment areas. Each redundant instrument provides input to one of two logic channels (Division 1 or 2).

Any high RHR equipment area ambient temperature or differential temperature for a division will initiate an isolation signal closing either the RHR/RCIC inboard or outboard isolation valves.

A bypass/test switch is provided in each logic channel for the purpose of testing the temperature monitor without initiating RHR system isolation.

differential pressure. Drywell pressure narrow range and wide range measurements are recorded in the control room with the narrow range measurement also indicated and annunciated in the control room.

Containment pressure normal and wide range are also measured with redundant channels, with each normal range channel being indicated, recorded, and annunicated for high containment pressure in the control room, and each wide range channel being recorded in the control room.

All pressure sensing lines which penetrate the containment have an isolation valve in-line which is controlled from the control room with valve position status lights indicated in the control room.

Redundant safety related channels exist for monitoring drywell temperature, drywell pressure, suppression pool temperature and level for recording on the Division 1 and Division 2 remote shutdown panels.

Three suppression pool level sensing lines form part of the suppression pool makeup system. However, the isolation valves for these lines are part of the containment atmoshphere monitoring system. Two redundant lines receive Division 1 and Division 2 power. The third line senses suppression pool level for high pressure core spray system instrumentation and receives Division 3 power. Containment humidity is determined by the plant computer system which receives electrical inputs from a non-safety related temperature and a moisture sensor, each of which are located so as to detect general containment conditions.

Indicators, annunciators, and recorders are located in the control room. Temperature sensors are located inside the containment and drywell. All controls, instrumentations and sensors have been selected to meet the normal, accident and post-accident worst case environmental conditions of temperature, pressure, humidity, radiation, and vibrations expected at their respective locations. Refer to Section 3.11 for equipment qualification.

(c) RCIC steam line pressure

(d) RHR area temperatures - differential and ambient

(e) RWCU area temperatures - differential and ambient

(f) RWCU differential flow

(g) RHR/RCIC steam line flow rate

(h) MSL tunnel temperatures - differential and ambient

(i) MSL temperatures, turbine building

(j) MSL flow

3. Neutron Monitoring System

(a) IRM neutron flux

(b) APRM neutron flux

4. Rod Pattern Control System

(a) Reactor Power Level

(b) Control Rod Selection

5. Recirculation Pump Trip System

(a) Turbine Stop Valve Closure

(b) Turbine Control Valve Fast Closure

6. Fuel Pool Cooling System

(a) Fuel Transfer Tube Drain Tank Level

(b) High Drywell Pressure

(c) Reactor Vessel Low Water Level (Level 1 & 2)

(d) Low Demineralizer Flow

(e) Fuel Pool High/Low Level (Alarm Only)

(f) Fuel Pool High Temperature (Alarm Only)

7. Containment Atmosphere Monitoring System

This system has no automatic protective actions. Its function is to monitor conditions and provide information.

radioactive materials, following postulated gross failures of the fuel or nuclear system process barrier, is kept within acceptable bounds.

d. Margin

The margin between operational limits and the limiting conditions of operation of the safety related systems are accounted for in technical specifications.

e. Levels

Levels requiring protective action are established in technical specifications.

18. Access to Set Point Adjustments, Calibration, and Test Points (IEEE Standard 279, Paragraph 4.18)

During reactor operation access to setpoint adjustments, calibration controls, and test points for the safety related systems variables described in Section 7.6 is under administrative control.

19. Identification of Protective Actions (IEEE Standard 279, Paragraph 4.19)

When any sensor of the safety related systems described in Section 7.6 exceeds its predetermined setpoint, a control room annunciator is initiated to identify that variable and a typed record is available from the process computer.

20. Information Readout (IEEE Standard 279, Paragraph 4.20)

The safety related systems described in Section 7.6 are designed to provide the operator with accurate and timely information pertinent to their status. This information does not give anomalous indications confusing to the operator.

21. System Repair (IEEE Standard 279, Paragraph 4.21)

During periodic testing of the safety related systems described in Section 7.6 (except as noted) the operator can determine any defective component and replace it during plant operation.

Replacement of IRM and LPRM detectors must be accomplished during plant shutdown. Repair of the remaining portions of the neutron monitoring channels may be accomplished during plant operation by appropriate bypassing of the defective instrument channel. The design of the system facilitates rapid diagnosis and repair.

TABLE 7.6-1

IRM SYSTEM TRIPS

Trip Function	Trip Action
IRM upscale	Scram, annunciator, red light display
IRM inoperative	Scram and rod block, annunciator, red light display
IRM upscale	Rod block, annunciator, white light display
IRM downscale	Rod block (exception on most sensitive scale), annunciator, amber light display
IRM bypassed	White light display

Note:

1. IRM is inoperative if module interlock chain is broken, operate-calibrate switch is not in operate position, or detector polarizing voltage is below 80 volts.

(b) 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 in the following sections. Figure 7.7-1 shows all the rod block functions on a logic diagram.

(1) With the mode switch in the SHUTDOWN position, no control rod can be withdrawn except during the single rod test. This enforces compliance with the intent of the shutdown mode.

(2) The circuitry is arranged to initiate a rod block regardless of the position of the mode switch for the following conditions:

a Any APRM inoperative alarm. This assures that no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or correctly bypassed.

b 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 earlier than the scram that is initiated on scram discharge volume high water level.

accommodate a scram. The setting is selected to initiate a rod block earlier than the scram that is initiated on scram discharge volume high water level.

c Scram discharge volume high water 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.

d Any Average Power Range Monitor (APRM) flow biased upscale rod block. The purpose of this rod block function is to avoid conditions that would require reactor protective system action if allowed to proceed. The APRM high flow biased rod block setting is selected to intitiate a rod block before the APRM flow biased upscale scram setting is reached.

(4) With the mode switch in the STARTUP or Refuel position, any of the following condition initiates a rod block:

a Any IRM upscale alarm. This assures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is correctly upranged during a reactor startup. This rod block also provides a means to stop rod withdrawal in time to avoid conditions requiring reactor protection system action (scram) in the event that a rod withdrawal error is made during low neutron flux level operations.

b Any Average Power Range Monitor (APRM) upscale rod block alarm. The purpose of rod block function is to avoid conditions that would require reactor protection system action 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.

c Any IRM downscale alarm except when range switch is on the lowest range. This assures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being correctly 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 intermediate range monitor is on scale if control rods are to be withdrawn.

d Any IRM inoperative alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available in that all IRM channels are in service or are correctly bypassed.

e Any Source Range Monitor (SRM) detector not fully inserted into the core when the SRM count level is below the retract permit level and associated IRM switches are on either of the two lowest ranges. This assures that no control rod is withdrawn unless all SRM detectors are correctly inserted when they must be relied on to provide the operator with neutron flux level information.

f Any SRM upscale level alarm and associated IRM range switches are below range "8". This assures that no control rod is withdrawn unless the SRM detectors are correctly 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.

g Any SRM downscale alarm and associated IRM range switches are on either of the two lowest ranges. This assures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring.

h Any SRM inoperative alarm and associated IRM range switches are below range "8". This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available.

i Any Intermediate Range Monitor (IRM) detector not fully inserted into the core. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available.

(c) Rod Block Bypasses

To permit continued power operation during repair or calibration of equipment for selected functions that provide rod block interlocks, a limited number of manual bypasses are permitted as follows:

(1) 1 SRM channel (1 on RPS Bus A or Bus B)
(2) 2 IRM channels (1 on Bus A and Bus B)
(3) 2 APRM channels (1 on Bus A and Bus B)

The permissible IRM and APRM bypasses are arranged in the same way as in the reactor protection system. See Section 7.2.1. The IRMs 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 same type of grouping and bypass arrangement is used for the APRMs. The arrangement allows the bypassing of one IRM and one APRM in each rod block logic circuit.

These bypasses are affected by positioning switches in the control room. A light in the control room indicates the bypassed condition.

b. Refueling Interlocks Operation

The refueling interlocks circuitry senses the condition of the refueling equipment and the control rods to prevent the movement of the refueling equipment or withdrawal of control rods (rod block). Redundant circuitry is provided to sense the following conditions:

1. All rods inserted

2. Refueling platform positioned near or over the core

3. Refueling platform main hoist fuel-loaded

4. Reactor Mode Switch in "Refuel" position.

The indicated conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operations and control rod movement (Table 7.7-3). A two-channel 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 in the rod position indicator probe. The rod-in switch must be closed for each rod before the all-rods-in signal is generated. RPIS control circuitry must indicate "all-rods-in" to allow refueling equipment to be used.

During refueling operations, no more than one control rod is permitted to be withdrawn; this is enforced by a redundant logic circuit that uses the all-rods-in signal and a rod selection signal from the RC&IS to prevent the selection of a second rod for movement with any other rod not fully inserted. Control rod withdrawal is prevented by comparison between the A and B portions of the RC&IS for rod position with a subsequent rod withdrawal block if necessary. The simultaneous selection of two control rods is prevented by the multiplexing action of the rod select circuitry and by feedback from the rod motion timer which latches the selected rod's

TABLE 8.1-2 (Continued)

Publication	Discussion
IEEE Std. 344-1971	All Class 1E electric equipment is seismically qualified in accordance with IEEE Std. 344-1971. Section 3.10 presents the details of the seismic qualification program and describes further compliance to IEEE Std. 344-1975 (as modified by Regulatory Guide 1.100) for certain components and equipment.
IEEE Std. 379-1977	Single failure criteria is applied to Class 1E systems in accordance with IEEE Std. 379-1977.
IEEE Std. 382-1972	Qualification of electric valve operators is in accordance with IEEE Std. 382-1972, as modified by Regulatory Guide 1.73.
IEEE Std. 383-1974	Cables, field splices and connections are type tested in accordance with IEEE Std. 383-1974.
IEEE Std. 384-1974	Separation criteria for Class 1E equipment and circuits is in accordance with IEEE Std. 384-1974, as modified by the discussion under Regulatory Guide 1.75.
IEEE Std. 387-1977	Application of standby diesel generators to the Class 1E power system is in accordance with IEEE Std. 387-1977. Type testing modifications for the HPCS diesel generator units are described in G.E. Topical Report NEDO-10905-2.[2]
IEEF Std. 415-1976	Preoperational test programs for the Class 1E power system are in accordance with the guidelines in IEEE Std. 415-1976 as described in Chapter 14.
IEEE Std. 450-1980	Maintenance, testing and replacement of Class 1E storage batteries are in accordance with IEEE Std. 450-1980.

TABLE 8.1-2 (Continued)

Publication	Discussion
Regulatory Guide 1.106	The Class 1E power system does not include thermal overload relays to protect motor operated valves; therefore, this Regulatory Guide is not applicable to the design.
Regulatory Guide 1.108	The guidelines presented in Regulatory Guide 1.108 are used in establishing preoperational and periodic test procedures for the standby and HPCS diesel generators, with the exception that "first out" annunciation is not used. The basis for this is individual protective trip alarms, which give the operator adequate information for correct action.
Regulatory Guide 1.118	Periodic testing of electric power and protection systems is in accordance with IEEE Std. 338-1977, as modified by Regulatory Guide 1.118.
Regulatory Guide 1.120	Refer to Section 9.5.1 for details.
Regulatory Guide 1.128	Class 1E batteries are designed and installed in accordance with IEEE Std. 484-1975, as modified by Regulatory Guide 1.128, except that a hydrogen survey will not be performed. Calculations indicate that the maximum hydrogen concentration in the battery area will be less than 0.001%.
Regulatory Guide 1.129	Class 1E batteries are maintained and tested in accordance with IEEE 450-1980, as modified by Regulatory Guide 1.129
Branch Technical Position ICSB 2	Standby diesel generators are type qualified in accordance with ICSB 2. The HPCS diesel generators are type qualified as described in Section 8.3.
Branch Technical Position ICSB 6	Capacity testing of Class 1E batteries is in accordance with ICSB 6.
Branch Technical Position ICSB 8	As required by ICSB 8, onsite diesel generators will not be used for peaking service.

turbine inlet (720 psig) in the run mode, the following is the sequence of operator actions expected during the course of the event. Once isolation occurs the pressure will increase to a point where the relief valves open. The operator should:

a. Monitor that all rods are in.

b. Monitor reactor water level and pressure.

c. Observe turbine coastdown and break vacuum before the loss of steam seals. Check turbine auxiliaries.

d. Observe that the reactor pressure relief valves open at their set point.

e. Observe that RCIC and HPCS initiate on low-water level.

f. Secure both HPCS and RCIC when reactor pressure and level are under control and it is verified that the initiation is not due to a LOCA.

g. Monitor reactor water level and continue cooldown per the normal procedure.

h. Complete the scram report and initiate a maintenance survey of pressure regulator before reactor restart.

15.1.3.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection and reactor protection systems except as otherwise noted.

Initiation of HPCS and RCIC system functions will occur when the vessel water level reaches the L2 set point. Normal startup and actuation can take up to 30 seconds before effects are realized. If these events occur, they will

A 5-second isolation valve closure instead of a 3-second closure is assumed when the turbine pressure decreases below the turbine inlet low pressure set point for main steam line isolation initiation. This is within the specification limits of the valve and represents a conservative assumption.

Reactor scram is initiated when the isolation valves reach the 10 percent closed position. This is the maximum travel from the full open position allowed by specification.

This analysis has been performed, unless otherwise noted, with the plant conditions listed in Table 15.0-1.

15.1.3.3.3 Results

Figure 15.1-4 shows graphically how the high water level trip and isolation valve closure stops vessel depressurization and produces a normal shutdown of the isolated reactor.

The main steam line isolation valves automatically close at approximately 28 seconds when pressure at the turbine decreases below 720 psig. Depressurization results in formation of voids in the reactor coolant and causes a rapid decrease in reactor power almost immediately. Reactor vessel isolation limits the duration and severity of the depressurization so that no significant thermal stresses are imposed on the reactor coolant pressure boundary. After the rapid portion of the transient is complete and the isolation effective, the nuclear system safety/relief valves operate intermittently to relieve the pressure rise that results from decay heat generation. No significant reductions in fuel thermal margins occur. Because the rapid portion of the transient results in only momentary depressurization of the nuclear system and because the safety/relief valves need operate only to relieve the pressure increase caused by decay heat, the reactor coolant pressure boundary is not threatened by high internal pressure.

15.1.3.3.4 Considerations of Uncertainties

If the maximum flow limiter were set higher or lower than normal, there would result a faster or slower loss in nuclear steam pressure. The rate of depressurization may be limited by the bypass capacity, but it is unlikely.

For example, the turbine valves will open to the valves-wide-open state admitting slightly more than the rated steam flow and with the limiter in this analysis set to fail at 130 percent we would expect something less than 23 percent to be bypassed. This is therefore not a limiting factor on this plant. If the rate of depressurization does change it will be terminated by the low turbine inlet pressure trip set point.

Depressurization rate has a proportional effect upon the voiding action of the core. If it is large enough, the sensed vessel water level trip set point (L8) may be reached initiating scram and turbine and feedwater pump trip early in the transient. Reactor scram will shut down the reactor. Since main turbine is tripped, the depressurization will be terminated.

15.1.3.4 Barrier Performance

Barrier performance analyses were not required since the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel or containment are designed. Peak pressure in the bottom of the vessel reaches 1,162 psig which is below the ASME code limit of 1,375 psig for the reactor coolant pressure boundary. Minimum vessel dome pressure of 790 psig occurs at about 30 seconds.

15.1.3.5 Radiological Consequences

While the consequences of this event do not result in any fuel failures, radioactivity is nevertheless discharged to the suppression pool as a result of SRV actuation. However, the mass input, and hence activity input, for this

TABLE 15.1-4

SEQUENCE OF EVENTS FOR FIGURE 15.1-4

Time-sec	Event
0	Simulate maximum limit on steam flow to main turbine.
2.1	Turbine control valves wide open.
2.28	Vessel water level (L8) trip initiates reactor scram and main turbine and feedwater turbine trips.
2.28	Turbine trip initiates bypass operation to full flow.
2.29	Main turbine stop valve reaches 90% open position and initiates recirculation pump trip (RPT).
2.38	Turbine stop valves closed. Turbine bypass valves opening to full flow.
2.4	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
5.2	Group 1 pressure relief valves actuated.
10.2	Group 1 pressure relief valves close.
25	Vessel water level reaches Level 2 (L2) setpoint.
28	Main steam line isolation on low turbine inlet pressure (720 psig).
33	MSIV closed. Bypass valves remain open, exhausting steam in steamlines downstream of isolation valves.
55 (est)	RCIC and HPCS systems flow into vessel (not simulated).

DSER ASB-4 Section 5.2.5 - Reactor Coolant Pressure Boundary Leakage Detection - The applicant is required to describe how the operator will determine the amount of leakage by observing the indication available to him, including the need for unit conversion and how a record of background leakage is maintained. Additionally, if the monitoring is computerized, discuss the backup procedures that are to be provided assuming failure of the computer.

Response

As primary method for detecting identified and unidentified leakage, the drywell floor drain sump level, and the drywell equipment drain sump pump level will be used to monitor flow rate (gpm) into the sump. Background leakage will be determined during startup testing.

Airborne particulate and gaseous radioactivity will be monitored in the drywell as a supplemental/qualitative method for determining high gross unidentified leakage. Correlating particulate and gaseous radioactivity readings with reactor coolant leakage rate is considered impractical in detecting increases in leakage rates of 1 gpm to 3 gpm and also for the maximum allowed sump leakage limit of 5 gpm. This position was formerly presented to the NRC by the Philadelphia Electric Company (PECO), with regard to the Limerick Generating Station, Units 1 and 2. The NRC Division of Licensing, in its letter to PECO, dated November 17, 1983, concluded that sufficient basis was provided to reconsider its position on this subject for Limerick. This basis is also considered applicable to the Perry plant design.

Condensate flow rate from the upper two drywell coolers (elevation 630'-1") will be monitored as a supplemental method of leak detection. Readout units are in gpm.

A record of background leakage shall be maintained in the control room. This record shall be kept by the control room operators and will be periodically reviewed to determine if any trends have developed.

Leakage monitoring for drywell equipment drain sump level and drywell floor drain sump level is contained in the ERIS computer. This is not, however, the primary display method.

(2) An annunciator to alarm whenever the charger goes into a current limiting condition.

(3) A temperature indicator to measure the battery room ambient temperature.

e. The voltage variation for an associated battery bus during any expected accident mode of operation should be within design specifications.

f. The direct current equipment should be rated and qualified for operation at the equalizing charge voltage and rated discharge voltage (typically 110 to 145 volts for a nominal 125 volt direct current system).

2. State if the battery charger has sufficient capacity to operate all nonaccident shutdown loads assuming the battery is not available. Also, state if the stability of the battery charger output is load dependent and, if so, describe.

Response

1. a. The status of main dc bus circuit breaker is monitored and annunciated in the control room to indicate that the battery has been disconnected from the switchgear bus.

b. The battery chargers will be tested as described in Section 8.3.2.1.5. Performance tests will be in accordance with the manufacturers' recommendations.