5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system (RCS) includes those systems and components that contain or transport fluids to or from the reactor core. These systems form a major portion of the nuclear system process barrier. This chapter provides information regarding the RCS and pressure-containing appendages out to and including isolation valving. This group of components is defined as the reactor coolant pressure boundary (RCPB) in Section 50.2(v) of 10 CFR 50 as follows:

The RCPB means all those pressure-containing components of boiling and pressurized water-cooled nuclear power reactors, such as pressure vessels, piping, pumps, and valves, which are:

- Part of the RCS.
- Connected to the RCS, up to and including all of the following:
  - The outermost containment isolation valve in system piping which penetrates primary reactor containment.
  - The second of the two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment.
  - The RCS safety relief valves.

Section 5.5 of this chapter also deals with various subsystems to the RCPB which are closely allied to it. These are briefly reviewed below.

The nuclear pressure relief system (NPRS) protects the RCPB from damage due to overpressure. To protect against overpressure, pressure-operated safety relief valves are provided to discharge steam from the nuclear steam supply system (NSSS) to the suppression pool. The NPRS also acts to automatically depressurize the NSSS in the event of a loss-of-coolant accident (LOCA) in which the high-pressure coolant injection (HPCI) system fails to maintain reactor pressure vessel (RPV) water level. Depressurization of the NSSS allows the low-pressure core cooling systems to supply enough cooling water to adequately cool the fuel.

The RCPB leak detection system, described in subsection 5.2.7, detects system leakage inside the primary containment so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The RPV and appurtenances are described in section 5.4. The major safety functions of the RPV are to maintain water over the core and to act as a radioactive material barrier. The RPV meets the requirements of applicable codes and criteria. The possibility of brittle fracture is

considered and suitable design and operational limits are established that avoid conditions where brittle fracture is possible.

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

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

The MSIVs automatically close to isolate the nuclear system process barrier in the event a pipe break occurs downstream of the isolation valves, thereby limiting the loss-of-coolant and the release of radioactive materials from the NSSS. Two MSIVs are installed on each main steam line, one inside and the other outside the primary containment. Closure of either of the two MSIVs acts to seal the primary containment in the event that a main steam line break occurs there.

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

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the NSSS under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available, i.e., hot standby. Another operational mode of the RHR system is low pressure coolant injection (LPCI). The LPCI operation is an engineered safety feature system for use during a LOCA. This operation is described in paragraph 6.3.2.2.4. Another mode of RHR system operation allows heat to be removed from the primary containment following a LOCA.

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

The following low-pressure systems interface with the high-pressure RCS on HNP-2:

- Radwaste systems.

- RHR system.

- Core spray (CS) system.

Due to the involvement of the RHR and CS systems in the emergency core cooling system function, the recommendations of BTP EICSB-3 are not required to be implemented for these systems. A description of overpressure protection for the RHR system is provided in section 6.3 and paragraph 7.3.1.2.3.

The radwaste systems comply with the intent of BTP EICSB-3 in that the systems cannot be overpressurized by the high-pressure RCS. The high-pressure RCS is connected to the radwaste system to facilitate drainage and venting for maintenance. Where maintenance drains are provided, the systems are separated by two normally closed, manually operated valves in series. The radwaste system also provides a collection point for gas and vapor venting from the RPV during RPV heatup. Two normally closed remote manually actuated, air-operated valves are provided with valve position indication in the main control room, and opening and closing evolutions are controlled administratively during startup and shutdown of the reactor.

In view of the size of the air-operated valves (drawing no. H-26000, valves F003 and F004) and the fact that the valves discharge into uninsulated drywell equipment drain piping which is of a much larger size (2-in.-nominal diameter connector pipe to a 4-in.-nominal diameter nonisolable collection header to the drywell equipment sump which is vented to the drywell volume), the failure of administrative controls for these valves would not cause overpressurization of the radwaste system.

5.1.1 SCHEMATIC FLOW DIAGRAM

A process flow diagram of the RCS denoting all major components, principal pressures, temperatures, flowrates, coolant volumes, and enthalpy under normal steady-state full-power operating conditions is presented in figure 5.1-1.

5.1.2 PIPING AND INSTRUMENTATION DIAGRAM

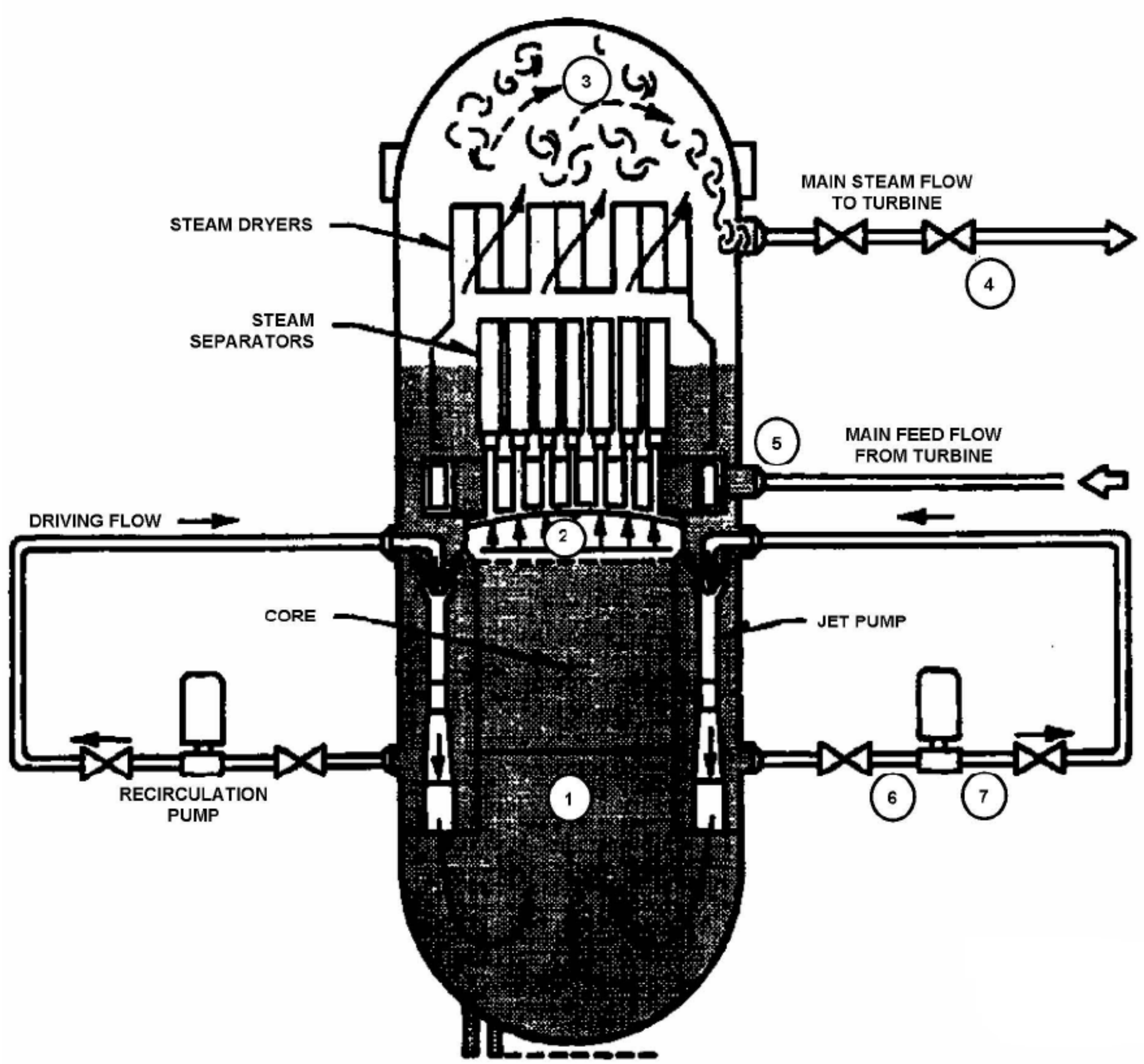
A piping and instrumentation diagram for the nuclear boiler system is presented in drawing nos. H-26000, H-26001 and H-26189.

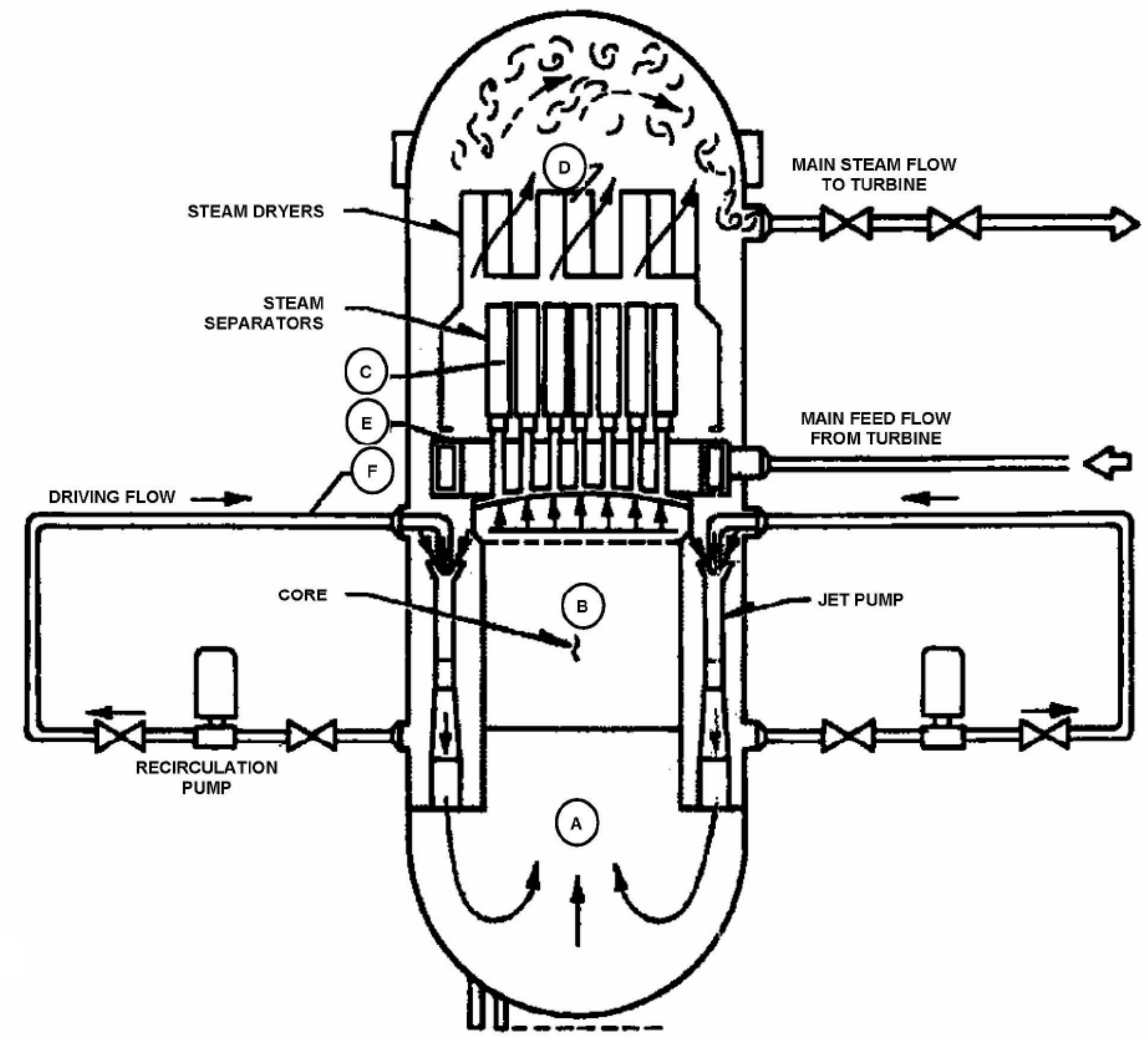
5.1.3 ELEVATION DRAWING

Sections through the reactor building showing the primary containment and the major pieces of equipment of the RCS are shown on drawing nos. H-26104 and H-26105.

	PRESSURE (Psia)	FLOW (lbs/hr)	TEMPERATURE (°F)	ENTHALPY (Btu/lb)
1. CORE INLET	1100	77 x 10^6	534.6	529.7
2. CORE OUTLET	1073	77 x 10^6	552	651.1
3. SEPARATOR OUTLET (STEAM DOME)	1060	12.171 x 10^6	551.7	1190.4
4. STEM LINE (2nd ISOLATION VALVE)	1025	12.171 x 10^6	579	1190.4
5. FEEDWATER INLET (INCLUDES CLEANUP RETURN FLOW)	1085	12.241 x 10^6	425.8	403.9
6. RECIRC PUMP SUCTION	1072	34.3 x 10^6	534	529.6
7. RECIRC PUMP DISCHARGE	1246	34.3 x 10^6	535	530.3

	VOLUME OF FLUID (ft^3)
A LOWER PLENUM	2844
B CORE	1525
C UPPER PLENUM & SEPARATORS	926
D DOME (ABOVE NORMAL WATER LEVEL)	5266
E DOWNCOMER REGION	4533
F RECIRC LOOPS & JET PUMPS	1236





ACAD 2050101

REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

REACTOR COOLANT SYSTEM FLOW DIAGRAM

FIGURE 5.1-1

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY (RCPB)

5.2.1 DESIGN OF RCPB COMPONENTS

5.2.1.1 Performance Objectives

5.2.1.1.1 Reactor Pressure Vessel (RPV) and Appurtenances

The objective of the RPV design is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the reactor. Design of the RPV and appurtenances provides the means for attaching pipelines to the RPV and for installing RPV internal components.

5.2.1.1.2 Reactor Recirculation System (RRS)

The objective of the RRS is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level.

5.2.1.1.3 Nuclear Pressure Relief System (NPRS)

The objective of the NPRS is to limit any overpressure that occurs during an anticipated operational occurrence (AOO).

5.2.1.1.4 Main Steam Line Flow Restrictors

The objective of the main steam line flow restrictors is to protect the fuel barrier by limiting the loss of coolant from the RPV before main steam isolation valve (MSIV) closure, should a rupture occur in a main steam line outside the primary containment.

5.2.1.1.5 Main Steam Line Isolation Valves

The objective of the MSIVs, one of which is on the drywell side while the other is just outside the primary containment, is to prevent damage to the fuel barrier by limiting loss of reactor coolant for a major steam piping leak outside the primary containment. MSIVs also limit radioactive releases to the plant environs.

5.2.1.1.6 Reactor Core Isolation Cooling (RCIC) System

The RCIC system provides core cooling during reactor shutdown by pumping makeup water into the reactor vessel in case of a loss of flow from the main feed system and is activated in time to preclude conditions which lead to inadequate core cooling.

5.2.1.1.7 Residual Heat Removal (RHR) System

The objectives of the RHR system are:

- To restore and maintain the coolant inventory in the RPV so that the core is adequately cooled after a loss-of-coolant accident (LOCA).
- To provide containment (suppression pool) cooling so that condensation of the steam resulting from the blowdown due to the design basis LOCA is ensured.
- To remove airborne particulates in the drywell and to reduce the temperature and pressure of the primary containment atmosphere post-LOCA. Crediting this function was added as part of the implementation of an alternative source term (AST)(reference subsection 15.1.11).
- To remove decay heat and residual heat from the nuclear steam supply system (NSSS) so that refueling and NSSS servicing can be performed.
- To supplement the fuel pool cooling and cleanup system (FPCCS) capacity, when necessary, with additional cooling capacity.

5.2.1.1.8 Reactor Water Cleanup (RWC) System

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

5.2.1.1.9 Nuclear System Leak Detection System (LDS)

The objective of the NSSS LDS is to detect leakage from the nuclear system process barrier and from systems essential to safe plant shutdown before predetermined limits are exceeded.

5.2.1.1.10 High-Pressure Coolant Injection (HPCI) System

The HPCI system supplies makeup water to the reactor vessel in the event of a LOCA or reactor isolation and failure of the RCIC system. The makeup water is required to maintain

sufficient reactor water inventory since steam generation will continue at a reduced rate due to the core fission product decay heat, even though the reactor has scrammed. A turbine-driven pumping system is used to supply demineralized makeup water from the condensate storage tank (CST) to the reactor; an alternate source of water is available from the suppression pool. The turbine is driven with a portion of the decay heat steam from the reactor vessel, and exhausts to the suppression pool.

5.2.1.1.11 Core Spray (CS) System

The CS system consists of two completely independent spray loops. The equipment for each loop consists of a CS pump, a sparger ring, a spray nozzle, and the necessary piping, valves, and instrumentation. Each loop pump takes water from the suppression chamber by suction and sprays the water through the sparger ring into the plenum chamber above the core.

The CS system is designed to deliver sufficient spray to each fuel bundle in the core to prevent fuel clad melting during loss-of-coolant conditions. The design is coordinated with the total emergency core cooling system (ECCS) in such a manner that for all rates of coolant loss from the primary reactor system, the core will be adequately cooled.

5.2.1.2 Design Parameters

Table 5.2-1 lists design temperature, pressure, and maximum test pressure for the RCPB structures and components. Stress analyses for RPV components are performed using the methods described in paragraph 5.4.6.4. A discussion of the input criteria for seismic design is contained in section 3.7.

The design requirements established to protect the principal components of the reactor coolant system (RCS) against environmental effects are discussed in subsection 3.11.2.

Due to intergranular stress corrosion cracking, the recirculation piping, stainless steel portions of the RHR suction and return lines, and a portion of the RWC piping have been replaced with Type 316 Nuclear Grade stainless steel. The extent of the replacement is described in table 3.2-1. The recirculation piping flow element is replaced with a flow element which has the same configuration as the original one and is made from Nuclear Grade CF3 material.

Boiling water reactor operating history has indicated that certain stainless steel piping in the RCS pressure boundary has been susceptible to stress corrosion cracking. To preclude potential cracking, the recirculation pump discharge valve 4-in. bypass lines have been removed from the original recirculation piping system and excluded in the replacement of the recirculation piping system. The control rod drive hydraulic return line has been removed from the RPV and rerouted within the CRD system. (See drawing no. H-26007.) The CRD return line RPV nozzle has been capped. The CS piping has been replaced with carbon steel, and the stainless steel safe end has been replaced with one of a low-alloy steel.

5.2.1.3 Compliance with 10 CFR 50, Section 50.55a

Compliance with the guidelines of 10 CFR 50, Section 50.55a, Codes and Standards, is tabulated in section 3.2.

5.2.1.4 Applicable Code Cases

Code cases that were applied to the RPV are:

- ASME Section III, 1968 Edition including Addenda through Summer 1970.
- 1332-5.
- 1441-1.
- 1459-1.
- 1401-1.

No code cases were applied for pumps, valves, and piping.

The only code case invoked in the replacement recirculation piping design was American Society of Mechanical Engineers (ASME) Code, Section III, 1980 Edition, Case N-122, "Stress Indices for Integral Structural Attachments, Class 1." This code case is used for calculating stresses in the pipe wall in the vicinity of rectangular lugs welded to the pipe wall.

5.2.1.5 Design Transients

5.2.1.5.1 Loading and Stress Criteria for RCPB Components Designed by Stress Analysis

The loading conditions may be divided into four categories: normal, upset, emergency, and faulted conditions. These categories are generically described in the ASME Boiler and Pressure Vessel Code, Section III, N-412, 1968 Edition. For the replaced recirculation piping system (RHR and RWC piping from their connections to the reactor pressure vessel, recirculation piping, and RHR suction, respectively) the loading conditions are service levels A, B, C, and D as described in the ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition. The actual loading combinations, design procedures, and acceptability criteria are tabulated in section 3.9. These tables include the pressure-retaining components of the RCPB. The seismic criteria for the RCPB are discussed in section 3.7.

5.2.1.5.2 Analyses of RCPB Pressure Parts of the Reactor Pressure Vessel

The RPV is designed in accordance with the ASME Boiler and Pressure Vessel Code (1968), Section III, its interpretations and applicable requirements for Class A vessels as defined therein, as of the Summer 1970 Addenda.

Both elastic and inelastic stress analysis techniques were used in the design of the RPV core support and reactor internal structures to show that stress limits were not exceeded. Before an inelastic stress analysis was performed on these components, the elastic (linear) system analysis was checked to see if the analysis required modification. The procedure is to perform a linear analysis with the stiffness of the inelastic component reduced to the stiffness value corresponding to the inelastic displacement value. A nonlinear dynamic analysis is performed if the natural frequencies of the system with reduced stiffness deviate significantly from that of the unreduced system.

Stress analysis requirements and load combinations for the RPV are tabulated in section 3.9. The RPV was designed for a minimum useful life of 40 years. However, aging management programs (subsections 18.1.2, 18.2.9, 18.2.12, 18.2.15, and 18.2.17) monitor the ongoing condition of the reactor vessel so that actions are taken to provide reasonable assurance that the vessel is capable of performing its intended function for 40 years and beyond.

5.2.1.6 Identification of Active Pumps and Valves

5.2.1.6.1 Classification of Pumps and Valves

Active components are those whose operability is relied on to perform a safety function, as well as reactor shutdown function, during the transients or events considered in the respective operating condition categories.

Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) are not relied on to perform the system function during the transients or events considered in the respective operating condition categories.

Active valves within the RCPB are shown in tables 3.9-33 and 3.9-34.

The isolation signals which activate the isolation valves are described in section 7.3.2.

The times for closed or open cycles are listed in ***Technical Requirements Manual (TRM) table T7.0-1 (incorporated by reference into the FSAR)*** and table 6.3-4***.***

Leaktightness capability requirements for all active valves are included in the applicable valve specifications. Valve parts forming the RCPB were pressure tested per the requirements of the Draft Nuclear Pump and Valve Code or ASME Boiler and Pressure Vessel Code, Section III. The maximum allowable leakage past valve seats is 2 cm^3/h/in. of seat diameter under the system design pressure during manufacturer's shop test.

There are no active pumps in the RCPB.

5.2.1.6.2 Design Methods and Procedures for Pipe Rupture

The design criteria employed to ensure that active components function as designed in the event of a pipe rupture are described in the following:

A. RRS Pump

1. The LOCA does not degrade pump coastdown performance in the unbroken loop to the extent that the core is deprived of adequate cooling.

2. The pump bearings have sufficient dynamic load capability at rated operating condition to withstand the design basis earthquake (DBE).

B. RRS Discharge Block Valves

1. The valve in the unbroken loop is capable of automatic closure after the LOCA.

2. The valve in the unbroken loop maintains pressure integrity and operability following the DBE.

3. The valve in the unbroken loop closes automatically on a signal initiated by low reactor water level or high drywell pressure.

4. The valve closes in the maximum time span specified in table 6.3-4.

5. The maximum permissible leak rate is conservatively estimated to be 5 gal/min.

C. The automatic depressurization system (ADS) portion of the safety relief valves (7 of 11 safety relief valves) is required to operate during a small break LOCA. The ADS is activated by simultaneous signals from:

- Drywell high pressure.

- RPV low water level.

- Output pressure from at least one LPCI or one CS pump.

D. Isolation Valves as Required for System Functions

1. Valves required for the ECCS remain operable, for both opening or closing, as required for system functions after an accident.

2. Valve operation is controlled by the signals described in subsection 7.3.2.

E. Pipe Rupture

Protection against dynamic effects of pipe rupture is described in section 3.6. Protection is provided on the assumption that either longitudinal (slot) failure or circumferential (guillotine) failure may occur at selected locations along the piping within the primary containment.

5.2.1.7 Design of Active Pumps and Valves

In order to ensure the functional performance of active valves of the RCPB, stringent design requirements were applied. There are no active pumps in the RCPB. Operability is ensured as described in the following paragraphs.

All active valves were qualified for operability assurance by first being subjected to the following tests:

A. Shop tests which include hydrostatic tests and seal leakage tests were performed as specified in the applicable code.

B. The valves are required to open and close within specified time limits when subjected to design or environmental conditions as required by applicable codes. These valves were subjected to cold hydrostatic tests and hot functional tests as part of the Preoperational Test Program.

Conservative seismic accelerations of 1.5-g horizontal and 0.144-g vertical were used simultaneously in the structural analyses. The above loads were combined with other normal and transient operational loads, and the worst-case combined stress levels were determined and shown to meet the stress criteria. Assurance is therefore provided that the components will function as required.

Active valves are also operated periodically, as required in the Technical Specifications. This repeated operability requirement throughout the life of the specified valve further provides assurance of reliable valve operation.

The representative combination of loads and analyses are tabulated in section 3.9.

5.2.1.8 Inadvertent Operation of Valves

A discussion of the design basis events and appropriate limits for this plant is given in chapter 15 and tabulated in section 3.9. The events in chapter 15 have been selected to envelope the most severe change in critical parameters from events that have been postulated to occur during planned operation.

5.2.1.9 Stress and Pressure Limits

The allowable stress limits and design loads for RCPB components are tabulated in section 3.9. Active valves of the RCPB are delineated in tables 3.9-33 and 3.9-34.

5.2.1.10 Stress Analysis for Structural Adequacy

Stress analysis is used to determine structural adequacy of pressure components of the RCPB under various operating conditions and earthquakes. Significant discontinuities such as nozzles and flanges are considered. In addition to the design calculations required by the ASME Codes, stress analysis is performed by methods outlined in the code appendices or by other methods applicable to the design condition through reference to analogous codes or other published literature.

Results of significant areas of consideration are tabulated for major components in section 3.9.

5.2.1.11 Analysis Method for Faulted Condition

In the event that an inelastic stress analysis was performed, the elastic (linear) system analysis was checked to see if the analysis requires modification in accordance with the procedure described in paragraph 5.2.1.5.2.

5.2.1.12 Protection Against Environmental Factors

The protection of the principal components of the RCS against environmental effects is discussed in section 3.11. Missile protection is discussed in section 3.5, and fire protection is discussed in subsection 9.5.1.

5.2.1.13 Compliance With Code Requirements

For components that were constructed in accordance with Section III of the ASME Boiler and Pressure Vessel Code, Subsection NB, the analytical calculations or experimental testing was performed to demonstrate compliance with the code. Brief descriptions of the mathematical or test models and the methods of calculation or testing, including any simplifying assumptions with summary of results, are tabulated and discussed in section 3.9.

5.2.1.14 Stress Analysis for Emergency and Faulted Condition Loadings

The types of stress analysis that were used for the emergency and faulted conditions are given in the tables in section 3.9.

5.2.1.15 Stress Levels in Seismic Category I Systems

A list of Seismic Category I systems and associated stress levels (i.e., seismic, deadweight plus pressure and LOCA) at all points of high changes in flexibility under the faulted conditions are tabulated in section 3.9.

5.2.1.16 Analytical Methods for Stresses in Pumps and Valves

The methods and criteria for analysis of stresses and deformations in the pressure boundary portions of Class 1 pumps and valves are as described in either the 1971 edition of the ASME Code, Section III, or the Draft Nuclear Pump and Valve Code.
The methods and criteria for design and acceptability of stresses as determined for the pressure boundary portions of Class 1 valves and safety relief valves are those described in the applicable portions of the ASME Code, Section III, and the Draft ASME Nuclear Pump and Valve Code. In the event that components supplied with geometries or design conditions for which code limits had not been developed, a complete description of the analytical methods and criteria used for evaluation of stresses and deformations were submitted by the manufacturer. The summary of the analyses for the RCPB components (analytical models, methods of calculation, and a summary of results) is presented in section 3.9.

5.2.1.17 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

5.2.1.17.1 Pump Shaft Critical Speed

The first critical speed of the recirculation pump shaft has been calculated to be above 130% of the operating speed. The absence of shaft vibration has been verified by testing the pump up to its maximum rated speed. The absence of vibration was further verified in the plant during preoperational testing.

5.2.1.17.2 Pump Bearing Integrity

Adequacy of the bearing design has been verified by full temperature and pressure performance tests conducted to simulate expected loads.

5.2.1.18 Operation of Active Valves Under Transient Loadings

The qualification test program to verify that active valves within the RCPB whose operability is relied upon to perform a safety function or to shut down the reactor operate under the transient loadings experienced during service life is described in the following subsections.

5.2.1.18.1 Motor-Operated Gate Valve

A motor operator built to the same design as that of the motor operator for the RRS gate valves has been tested to demonstrate its performance capability under expected operating conditions, including the containment environment after the LOCA. Performance was tested under maximum moisture, pressure, and temperature conditions after exposure to lifetime radiation dose and under design basis seismic conditions. The specific conditions under which the operators were qualified are provided in section 3.11.

5.2.1.18.2 Main Steam Line Isolation Valves

Components of the MSIVs, which are required to operate during transient conditions and whose functional capabilities are sensitive to the abnormal ambient pressure and temperature associated with the transient, were subjected to a test sequence that simulates the abnormal ambient conditions. Functional requirements were verified throughout the test sequence. Components prototypical of HNP-2 valve components were tested.

The MSIVs have been tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III. Thermal transient loadings on the MSIVs were not simulated, but were shown to be acceptable by analysis.

5.2.1.18.3 Safety Relief Valves

The safety relief valves are subjected to tests that simulate conditions experienced during service life.

5.2.1.18.4 Other Provisions to Ensure Operability

To ensure operability of active valves under the transient loadings to be experienced during plant service life, design specifications include the following requirements:

A. Valve bodies and yoke structures are designed to withstand seismic forces.

B. Valve operators are sized to open or close under the maximum differential pressure across the valve seat, dictated by the transient service conditions.

C. Valves are qualified by analysis or prototype tests at the vendor's shop before delivery to substantiate the vendor's guarantee that they will operate under actual service pressure conditions.

D. All motor-operated valves are equipped with handwheels so that motors can be declutched and valves cycled manually after installation.

5.2.1.19 Field Run Piping

A discussion of field run piping and associated simplified procedures for the design and installation of field run piping is presented in subsection 3.7A.3.14.

5.2.2 OVERPRESSURIZATION PROTECTION

5.2.2.1 Location of Pressure Relief Devices

Drawing nos. H-26000 and H-26001 show the schematic location of pressure-relieving devices for the RCS.

5.2.2.2 Mounting of Pressure Relief Devices

5.2.2.2.1 Safety Design Bases

The NPRS is designed:

- To prevent overpressurization of the nuclear system in order to prevent failure of the nuclear system process barrier due to pressure.
- To provide automatic depressurization for small breaks in the nuclear system so that the LPCI and the CS systems can operate to protect the fuel barrier.
- Such that the safety relief valve discharge piping can accommodate forces resulting from relief action and be supported for reactions due to flow at maximum relief discharge capacity so that system integrity is maintained.
- For testing prior to nuclear system operation and for verification of the operability of the pressure relief system.
- To withstand adverse combinations of loadings and forces resulting from operation during AOOs, accidents, or special events.

5.2.2.2.2 Power Generation Design Bases

The NPRS safety relief valves are designed to:

- Discharge to the primary containment suppression pool.
- Properly reclose following a plant isolation or load rejection so that normal operation can be resumed as soon as possible.

5.2.2.2.3 Description

The NPRS consists of 11 safety relief valves located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system.

The three-stage pilot-operated safety relief valve consists of two principle assemblies: the top works section and the main stage section. As shown in figure 5.2-2, the top works consists of a pilot assembly (6), second-stage assembly (3), and air operator (10). Reactor pressure is communicated through port (5) to the pilot (6). When the reactor pressure reaches the pilot setpoint, the pilot disc (7) lifts and releases pressure to the second-stage disc chamber (1). The bellows holds the pilot disc open as long as the pressure is at the setpoint. The open pilot releases pressure to open the second-stage disc (2). The pressure opens the second-stage disc and forms part of the path that releases the steam from the chamber (8) out of port (9). The pressure in chamber (8) drops quickly and differential pressure across the main piston opens the main stage.

The principal innovations of the design and how they relate to improved performance are described as follows:

A. The three-stage SRV is designed and tested to have zero leakage at the pilot (6), second stage (2), and main stage. In a three-stage valve, the pilot disc seating stress is directly proportional to the reactor pressure as system pressure is utilized to create the seating force. The pilot disc seating stress increases proportionally up to abutment pressure, at which point further pressure increases result in pilot disc lift and, subsequently, main disc lift.

B. The pilot valve is not connected directly to the main piston chamber (8). If there is leakage past the pilot, it comes from the inlet pressure port (5) and does not pass the pilot (6) unless the pressure setpoint is reached. This maintains the pressure in chamber (8). Testing has shown that if leakage occurs between port (5) and chamber (1), there is not appreciable effect on setpoint performance; however, pilot leakage above calculated amounts may cause the valve to open and blow down the reactor. Pilot and second-stage thermocouples are installed in the three-stage SRV to provide indication of leakage in the MCR, should it develop.

C. This approach eliminates the following problems that have occurred with pilot-operated safety relief valves in the past. These problems are:

- Switch failures.
- Short circuits in switch wiring.
- Setpoint drift.
- Valve leakage.

D. The air actuator (10) is separate from the mechanical assembly but uses the same second-stage depressurization chamber, which opens the main valve.

The topwork's base and pilot body are Inconel 600 (ASME-SB-564). The seats of both the pilot and the second stage are Inconel 600 (ASME-SB-166) with Stellite 6 hard facing.

The safety relief valves provide two main protection functions:

A. Overpressure Safety Operation

The valves function as safety valves and open to prevent nuclear system overpressurization.

B. Depressurization Operation

The ADS valves open automatically as part of the ECCS for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from drawing no. H-26000.

The majority of events that lead to actuation of the primary system safety relief valves are those that initially or eventually produce a nuclear system pressure increase. These pressure increase events result from sudden reductions of steam flow while the reactor is operating at power.

Table 5.2-4 shows the set pressures of the safety relief valves used for pressure relief during occurrences of reactor pressure increase.

A list of the events that are expected to activate the primary system safety relief valves is presented in table 5.2-4. This table also lists the number of valves expected to operate during the initial blowdown of the valves and the expected duration of this first blowdown. The duration of each relief discharge should in most cases be < 5 s. Remote-manual actuation of the valves from the main control room (MCR) is provided to minimize the total number of these discharges, with the intent of achieving extended valve seat life.

The safety relief valves are designed to operate in the accident environments shown in table 3.9-34.

The environmental design requirements for the electrical portion of these valves are provided in the Plant Hatch Central File.

Each safety relief valve discharge is piped to the suppression pool. Each valve is of the pilot-operated type with the pilot spring-loaded to close. To prevent backpressure from affecting the pilot spring setting for the safety relief valves, the pilot bonnet is vented to the drywell for pressure equalization.

The safety relief valves used in HNP-2 are manufactured by Target Rock. All valves are equipped with air accumulators and can be pneumatically operated. Any of the 11 valves can be pneumatically operated by manual action from the MCR. No particular setpoint applies to

this method of operation as the operator may open a valve at his discretion for blowdown or test over a wide-pressure range.

Seven of the 11 safety relief valves are selected for ADS use. Initiation is automatic, after a 130-s time delay, from RPV water levels 1 and 3, together with high drywell pressure or a sustained RPV water level 1 signal after a 13-min time delay with an RPV water level 3 signal.

In the event of an anticipated transient without scram (ATWS), ADS operation can be manually inhibited. This enhances SLCS effectiveness by allowing a minimum RPV water level to be maintained and by preventing boron loss to the torus. This mode of operation is described in paragraph 7.3.1.2.2.

The remaining four valves are used for the low-low set (LLS) relief logic system.

The LLS system is an automatic safety relief valve control system which will initiate upon concurrent signals of any safety relief valve opening and high reactor pressure. The LLS controls preselected safety relief valves by use of the pneumatic actuator to open and close at predetermined setpoints which are lower than the pilot actuation setpoints. This results in a longer blowdown, lowered reactor pressure, and reduced number of safety relief valve actuations. The LLS system is described in subsection 5.5.17.
All 11 valves that function in a pressure-responsive (safety valve action) mode are listed in table 5.2-4.

The mechanical actuation mode is augmented by an electrical actuation logic used as a backup. Each steam relief valve can be actuated by its electric pilot solenoid valve. Each of the four steam lines is monitored by a pressure transmitter tied to three trip units (drawing nos. H-26000 and H-26001). The setpoints for the electrical backup are distributed among the 3 groups listed in table 5.2-4. Each of the three trip units is set to one of these group settings. The trip units reset at a pressure below the mechanical closing pressure (drawing nos. H-24709 through H-24711). This redundant control capability is, in itself, nonsafety related and is isolated by fuses from the safety-related portion of the pilot valve's circuit that serves either the ADS or the LLS system. The equipment serving the backup functions is installed and procured as if it were required to be safety related, but is nonsafety related (reference 14).

For automatic actuation of the ADS three-stage safety relief valve(s), an external pneumatic operator is provided to open the second-stage disc, the pressure in chamber (8) drops quickly, and differential pressure across the main piston (4) opens the main stage valve. This operation permits the main disc to open at any valve inlet pressure above 100 psig for a three-stage safety relief valve. Once open, the main disc will stay open down to an inlet pressure of 50 psig during pneumatic actuation. The control system for the actuator for depressurization operation is described in section 7.3.

Each safety relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Steam flow through the safety relief valve discharge line is indicated by both temperature and pressure indicators located on the discharge lines. (See drawing no. H-26000.) The safety relief valve discharge piping is designed to limit valve outlet pressure to 40% of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive

pressure at the valve discharge when the valve is again opened. For this reason, one or two vacuum relief valves are provided on each safety relief valve discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. The safety relief valves are located on the main steam line piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steam lines are more accessible during a shutdown for valve maintenance.

Each of the safety relief valves provided for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators ensure that the valves can be held open following failure of the air supply to the accumulators. They are sized to be capable of opening the valves twice and holding them open against 70% of maximum allowable drywell pressure (0.70 x 62 psig = 43.4 psig). This is equivalent to four-to-five actuations of the pilot valve with the drywell at atmospheric pressure following the loss of pneumatic supply to the accumulator. Assuming an allowable leakage rate of 4.5 sf^3/h, the accumulator can provide 2 actuations during the first ½ h following the loss of pneumatic supply to the accumulator. Only one actuation of any three ADS valves is needed for depressurization.

The elevated drywell pressure specified above is the result of the largest primary system break for which ADS is required. For smaller breaks in the drywell or for breaks outside the drywell, the accumulator availability will be considerably extended. For events not involving breaks in the drywell, accumulator capacity is sufficient to ensure multiple safety relief valve actuations for > 2 h.

The ADS accumulators have a volume of 5.48 ft^3 and each ADS valve requires up to 40 $in.^3$/actuation.

The NPRS depressurizes the nuclear system sufficiently to permit the low-pressure coolant injection (LPCI) and CS systems to operate as a backup for the HPCI system. Automatic depressurization occurs when some of the safety relief valves are opened automatically. The signal for the safety relief valves to open and to remain open is based on simultaneous signals from:

- Drywell high pressure.
- RPV water levels 1 and 3 sustained for 130 s.
- Output pressure from at least one LPCI or one CS pump.

<u>OR</u>

- RPV water level 1 sustained for 13 min.
- RPV water level 3 sustained for 130 s.
- Output pressure from at least one LPCI or one CS pump.

Further descriptions of the operation of the automatic depressurization feature are found in sections 6.3 and 7.3.

The nuclear system can be depressurized manually if the main condenser is not available as a heat sink after reactor shutdown. The safety relief valves are operated by remote-manual controls from the MCR.

5.2.2.2.4 Safety Evaluation

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

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

The safety relief valves are set to open by self-actuation (overpressure safety mode - table 5.2-4). This satisfies ASME Code specifications for safety valves, because all valves open at < 1250 psig (nuclear system design pressure). A nonsafety electrical backup to the mechanical relief is wired to open the safety relief valve at setpoints distributed among three groups (table 5.2-4).

Two major transients (the closure of all MSIVs and a turbine trip with a failure of the turbine steam bypass system valves to open) provide the most severe events resulting in a nuclear system pressure rise.

The transient produced by the closure of all MSIVs represents the most severe event resulting in a nuclear system pressure rise when direct scrams are ignored. The required safety valve capacity is determined by analyzing the pressure rise from this event. Original analyses assumed the plant to be operating at the turbine-generator design conditions at a maximum vessel dome pressure of 1020 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. The analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME Code allowable pressure in the nuclear system (1375 psig). The sequence of events assumed in this analysis was investigated to meet Code requirements and to evaluate the pressure relief system exclusively.

Increase of the initial reactor pressure relative to the initial value used in the overpressure report analysis has been investigated and shown to have the following effects. For the case of pressure scrams (failure of flux scram and direct trip scram), increasing the initial pressure progressively reduces the peak pressure reached because the initial pressure is closer to the scram setpoint, thus resulting in a more rapid termination of the transient.

For the case of flux scrams (failure of direct trip scram), increasing the initial pressure results in an increase of the peak pressure reached, which is less than half of the initial pressure increase as shown in figure 5.2-5. Thus, for HNP-2, the maximum transient pressure cannot increase by more than 10 psi; thus, the event would still be well within Code allowable limits.

It should also be noted that there is a very low probability that the initial pressure could be above the analyzed initial value during normal plant operation. This follows from the fact that the operating pressure setpoint control must be set during plant startup to the value which corresponds to the established turbine stop valve conditions required at 100% power operation. The vessel dome pressure increases automatically as power is increased, and any deviation would soon become obvious to the operator. Under the general requirements for protection against overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, credit can be allowed for a scram from the reactor protection system (RPS). In addition, credit is derived when determining the required safety relief valve capacity. The safety relief valve performance requirements were updated in references 18 and 19, and are reanalyzed each reload.

The design basis which employs the neutron flux scram for determining the required capacity of the pressure relieving dual-purpose safety relief valves is in full compliance with all requirements of ASME Section III, 1968 Edition including Addenda through Summer 1970. This design basis is conservative because the neutron flux scram is the second or backup signal to produce a reactor scram for the transient on which valve sizing is based; the reliable hard-wired scram from MSIV position switches having been assumed to fail. In addition, this design basis using the neutron flux scram is coupled with an availability index $I_A \geq 0.99999$ for the overpressure protection system. The subject of safety relief valve sizing for the original plant design is treated more fully in supplement 5A.

Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety relief valve capacity of nuclear vessels under the provisions of the ASME Code.

The loadings which the main steam pipe and relief valve discharge pipe impose on the safety relief valves include:

- The thermal expansion effects of the connecting piping.

- The dynamic effects of the piping due to earthquake.

- The jet force exerted on the safety relief valves during the first millisecond after the valve is opened and prior to the time steady-state flow has been established. (With steady-state flow, the dynamic flow reaction forces is self-equilibrated by the valve discharge piping.)

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

In no case will allowable valve flange loads be exceeded nor will the stress at any point in the piping exceed code allowables for any specified combination of loads.

The automatic depressurization capability of the NPRS is evaluated in section 6.3.

Criteria for the selection of safety relief valves require that the valves:

- Meet the requirements of ASME Section III, 1968 through 1970 Addenda

- Qualify for 100% of nameplate capacity credit for overpressure protection function.

- Meet additional performance criterion such as response time, etc., necessary to provide relief functions.

The safety relief valve discharge piping is designed, installed, and tested in accordance with the ASME Code, Section III.

A temperature element is installed in the discharge line from each safety relief valve. Each temperature element is connected to a temperature recorder in the control room. When a safety relief valve opens, discharge line temperature increases and the temperature recorder provides a permanent record of valve actuation.

5.2.2.2.5 Tests and Inspections

The safety relief valves are tested in accordance with the manufacturer's quality control procedures to detect defects and to prove operability prior to installation. The following tests are conducted:

- Hydrostatic test at specified test conditions as defined in the applicable code.
- Seat leakage test at 93% of set pressure.
- Set pressure test: The valve is pressurized with saturated steam, or other appropriate test medium, with the pressure rising to the valve set pressure.
- Response time test: Each safety relief valve is tested to demonstrate acceptable response time.

The valves are installed as received from the factory. The setpoints are adjusted, verified, and indicated on the valves by the vendor. Manual and remote opening circuitry of each safety relief valve is verified during the preoperational test program.

The valves are mounted on 6-in. diameter, 1500-lb primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. The external surface and seating of all safety relief valves are 100% visually inspected when the valves are removed for maintenance or bench checks.

5.2.2.3 Report on Overpressure Protection

An overpressure protection report for the original plant design is provided in supplement 5A. The report supplies sufficient information and documentation to show compliance with all the requirements of Article 9 of the ASME Code, Section III, 1968, including summer 1970 addenda. Included also is the design basis for the sizing of the safety relief valves, the overpressure protection analysis, the analysis of the safety valve (RPS availability), and the effects of the vessel pressure transients of various combinations of valve failures.

As described in subsection 15.4.2, overpressure protection is considered a potentially limiting event for reloads and plant modifications that can increase the peak RPV pressure during pressurization events. As a result, overpressure protection was analyzed for extended power uprate core power of 2763 MWt[18] and is reanalyzed each operating cycle as part of the process for demonstrating compliance with the ASME Boiler and Pressure Vessel Code. The reload report that provides the analysis results for the reload applicable to the current FSAR revision is identified in table 15.1-1. The following discussion provides the results of the extended power uprate analysis that demonstrates the acceptability of the increase in rated power level.

The analysis for extended power uprate confirmed that closure of all MSIVs with a flux scram is the most limiting event associated with the overpressure protection requirements. In the

extended power uprate analysis of overpressure protection, the analysis methods described in subsection 15.1.7 were used. The 1-D transient analysis model was used to simulate the event. The key initial conditions and analysis assumptions are provided in table 5.2-5. Figure 5.2-3 shows the analysis results. The peak calculated RPV bottom head pressure is 1347 psig, which is well within the event acceptance limit of 1375 psig.

The impact of thermal power optimization (2804 MWt) and reactor operating pressure increase to 1060 psia has been evaluated with a peak calculated RPV bottom head pressure increase to 1349 psig, which is well within the event acceptance limit of 1375 psig.

5.2.3 GENERAL MATERIAL CONSIDERATIONS

5.2.3.1 Material Specifications

The principal pressure-retaining materials and the appropriate material specifications for the RCPB components are listed in table 5.2-6.

5.2.3.2 Compatibility With Reactor Coolant

The construction materials exposed to the reactor coolant are:

- Solution-annealed austenitic stainless steels (both wrought and cast) Types 304, 304L, 316, and 316L.
- Nickel-base alloys, Inconel 600 and Inconel X750.
- Carbon steel and low-alloy pressure vessel steel.
- Some 400 series martensitic stainless steel, all tempered at a minimum of 1100°F.
- Colmonoy and Stellite hardfacing materials.

All of these construction materials are resistant to stress corrosion in the boiling water reactor (BWR) coolant. General corrosion on all materials except carbon and low alloy steel is negligible. Conservative corrosion allowances are provided for all exposed surfaces of carbon or low-alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water quality specifications. No detrimental effects will occur on any of the materials from allowable contaminant levels in the high purity reactor coolant. Radiolytic products in a BWR have no adverse effects on the construction materials.

5.2.3.2.1 BWR Water Quality Effects On Sensitized Stainless Steel

Boiling water reactor primary water contains 0.2 to 0.4 ppm oxygen during normal operation; these levels are inherent in the operating characteristics of the BWR. The oxygen content is the direct result of radiolysis and cannot be controlled.

Oxygen levels in the range of 8.0 to 100 ppm in highly accelerated screening tests have been shown to have some effect on the stress corrosion cracking susceptibility of furnace-sensitized stainless steel.

However, at the time of original construction, there was no substantiated evidence which indicated that these very severe screening tests could be used to predict performance of as-welded SS304 in normal BWR service.

Subsequent extensive laboratory testing, plus operating BWR experience, has shown that oxygen levels of 0.2 to 0.4 ppm can cause intergranular stress corrosion cracking (IGSCC) given sufficient stress and susceptible material condition. As-welded Types 304 and 316 have been found in some cases to be susceptible to IGSCC in the weld heat-affected zone in highly stressed joints. However, a large body of operating reactor experience has shown that at lower stresses these materials perform satisfactorily.

5.2.3.2.2 Stress Corrosion Resistance of Type 316 Nuclear Grade

For superior resistance to IGSCC in the BWR environment, Type 316 Nuclear Grade was used for systems such as the replacement recirculation system piping, stainless steel portions of RHR pipe, and RWCU pipe. This material has been demonstrated to be highly resistant to IGSCC.(6)

5.2.3.3 <u>Compatibility With External Insulation and Environmental Atmosphere</u>

The RCPB is insulated with an all-metal (stainless steel and aluminum) reflective-type insulation in compliance with Regulatory Guide 1.36 (February 1973). This type of insulation does not contain any silica, fluorides, or chlorides. It does not contribute to surface contamination, and it has no effect on the stainless steel components of the RCPB. The insulation is designed for a 40-year service life; however, this insulation is monitored so that actions are taken to provide reasonable assurance that the insulation is capable of fulfilling its intended function for 40 years and beyond.

The RRS piping, valves and pump casings, the stainless steel portions of the RHR, and the drywell portions of the RWC are covered with a glass fiber type insulation comprised of a flexible light-density, fibrous glass pad insulation, encapsulated in woven glass cloth forming a composite blanket. The blanket is then covered by stainless steel jackets and a mechanism for locating and identifying each weld under the insulation. Removable insulation sections are provided at all field welds to facilitate periodic inspection as required by the ASME Boiler and Pressure Vessel Code, Section XI rules for inservice inspection of nuclear reactor coolant systems. This insulation is designed for a 40-year service life; however, this insulation is

monitored so that actions are taken to provide reasonable assurance that the insulation is capable of fulfilling its intended function for 40 years and beyond.

5.2.3.4 Chemistry of Reactor Coolant

Reactor coolant chemistry controls are based upon BWRVIP-190, "BWR Water Chemistry Guidelines," or latest approved industry guidance which was developed by an industry committee of chemistry and materials specialists and considered available field and laboratory data. BWRVIP-190, or the latest approved industry guidance, provides a flexible approach to reactor coolant chemistry control and includes information on technical bases, options for different chemical control strategies, and data evaluation techniques. Subsection 18.2.1 provides further information regarding reactor coolant chemistry controls.

The TRM establishes upper limitations for reactor coolant chemistry during all operating modes.

5.2.4 FRACTURE TOUGHNESS (HNP-1 AND HNP-2)

The information provided in this section is applicable to both HNP-1 and HNP-2, unless specified otherwise.

5.2.4.1 Compliance With 10 CFR 50, Appendix G, Fracture Toughness Requirements

Nuclear Regulatory Commission (NRC) 10 CFR 50, Appendix G,[7] specifies fracture toughness requirements to provide adequate margins of safety during the operating conditions to which a pressure-retaining component may be subjected over its service lifetime. The limits for pressure and temperature (P/T) are required by 10 CFR 50, Appendix G, for three categories of operation:

- Hydrostatic pressure tests and leak tests (curve A).
- Core not critical heatup/cooldown (curve B).
- Core critical (curve C).

10 CFR 50, Appendix G, requires that P/T limit curves for the reactor pressure vessel (RPV) be at least as conservative as those obtained by applying the of the 1989 American Society of Mechanical Engineers (ASME) Code, Section XI, Appendix G[21] methodology.

HNP-1 and HNP-2 P/T limit curves for 54 effective full power years (EFPYs) are based upon the 1989 ASME Code, Section XI, Appendix G, methodology with the following two modifications:

1. Use of Code Case N-588.

   This Case permits both the postulation of a circumferentially-oriented flaw in lieu of an axially-oriented flaw for the evaluation of RPV circumferential welds and the use of the revised formula for stress intensity factors due to pressure and thermal gradient for axial flaws.

2. Use of Code Case N-640.

   This Case permits the use of the plane strain fracture toughness (K_{ic}) curve instead of the crack-arrest fracture toughness (K_{ia}) curve for RPV materials in determining the P/T limits.

HNP-1 and HNP-2 Technical Specification 3.4 show all three operating limit curves, including irradiation shift of the core beltline region curves to their positions at end-of-life (EOL).

5.2.4.1.1 Method of Initial RT_{NDT} Evaluation

For the purpose of setting the operating limits, the initial RT_{NDT} was determined from the toughness test data taken in accordance with requirements of the Code and the General Electric (GE) purchase specification to which the RPV was designed and manufactured. These toughness test data, Charpy V-Notch and drop-weight nil ductility transition temperature (NDTT), were analyzed to establish compliance with the intent of 10 CFR 50, Appendix G. Because all toughness testing needed for strict compliance was not required at the time of RPV procurement, some toughness results are not available. For example, longitudinal Charpy V-Notch, instead of transverse, was tested, usually at a single test temperature of + 10ºF or + 40ºF, for absorbed energy. Also, at the time, either Charpy V-Notch or NDTT testing was permitted; therefore, in some cases both tests were not performed as is currently required. To substitute for this absence of certain data, toughness property correlations were derived for the vessel materials in order to give a conservative estimate of RT_{NDT}, compliant with the intent of 10 CFR 50, Appendix G, criteria. These toughness correlations vary, depending upon the specific material analyzed, and were derived from NEDC-32399-P, "Basis for GE RT_{NDT} Estimation Method." [27]

In the case of vessel plate material (SA-533 Grade B, Class 1), the predicted limiting toughness property is either NDTT or transverse Charpy V-Notch 50 ft-lb temperature of - 60°F, whichever is greater. As a matter of practice, where NDTT results are missing, NDTT is estimated as the longitudinal Charpy V-Notch 35 ft-lb transition temperature. The transverse Charpy V-Notch 50 ft-lb transition temperature was estimated from longitudinal Charpy V-Notch data in the following manner. The lowest longitudinal Charpy V-Notch energy, if below 50 ft-lb, was adjusted to derive a longitudinal Charpy V-Notch 50 ft-lb transition temperature by adding 2°F per ft-lb to the test temperature. If the actual data equaled or exceeded 50 ft-lb, the test temperature was derived by interpolation or conservatively taken as the transition temperature. Once the longitudinal 50 ft-lb temperature was derived, an additional 30°F was added to account for the orientation change from longitudinal 50 ft-lb to transverse 50 ft-lb.

For forgings (ASTM A508, Class 2), the predicted limiting property is the same as for vessel plates, and the RT_{NDT} was estimated in the same way as for vessel plates.

For the vessel weld metal, the predicted limiting property is the Charpy V-Notch 50 ft-lb transition temperature - 60°F, as BWR materials experience indicates that drop-weight NDTT values are typically - 50°F or lower for weld materials. The Charpy V-Notch 50 ft-lb temperature was derived in the same way as for the vessel plate material, except the 30°F addition for orientation effects was omitted since there is no principal working direction in weld metal. When NDTT values are available, they are also considered, and the RT_{NDT} *is taken as the higher of either the NDTT or the 50-ft-lb temperature minus 60ºF. When the NDTT is not available, the* RT_{NDT} *shall not be < -50ºF, since lower values are not supported by the correlation data.*

For the vessel weld heat-affected zone (HAZ) material, the RT_{NDT} *was assumed the same as for the base material, since ASME Code weld procedure qualification test requirement, and post-weld heat treatment data indicate this assumption is valid.*

Original closure bolting material (ASTM A540, Grade B23 or B24) toughness test requirements was for Charpy V-Notch 30 ft-lb energy at 60°F below the bolt-preload temperature. Considering 10 CFR 50, Appendix G, requirements of 45 ft-lb and 25 mil lateral expansion at the bolt-preload or lowest service temperature, some closure stud materials do not meet 45 ft-lb absorbed energy at + 10°F, and mil lateral expansion results were not reported. Based on fabrication data showing 30-ft-lb CVN energy at 10ºF, the lowest service temperature for the closure studs is 70ºF.

Calculated values of initial RT_{NDT} *for HNP-1 are shown in table 5.2-9. GE provided similar data for HNP-2.*

5.2.4.2 Adjusted Reference Temperature at 54 EFPYs

The effect upon adjusted reference temperature (ART) due to irradiation in the beltline materials is determined according to the methods specified in Regulatory Guide (RG) 1.99, Rev 2,[8] as a function of neutron fluence and the element contents of copper (Cu) and nickel (Ni). The specific relationship from RG 1.99, Rev 2 is:

$$ART = \text{Initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin}$$

where:

ΔRT_{NDT} = $CF * f^{(0.28-0.10 \log f)}$

Margin = $2\sqrt{\sigma_I^2 + \sigma_\Delta^2}$

CF = chemistry factor.

f = 1/4T fluence (n/cm^2) divided by 10^{19}.

σ_I = standard deviation on initial RT_{NDT} which is taken to be 0°F.

σ_Δ = standard deviation on ΔRT_{NDT}, 28°F for welds and 17°F for base material, except that σ_Δ need not exceed 0.50 times the ΔRT_{NDT} value.

ΔRT_{NDT} is a product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in RG 1.99, Rev 2 or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the chemistry factor (CF) was determined using the tables in RG 1.99, Rev 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence, and the calculational procedures. RG 1.99, Rev 2 describes the methodology to be used in calculating the margin term.

The 54-EFPY peak fluence values for HNP-1 and HNP-2, used to calculate the 54 EFPYs 1/4T fluence values are provided in Table 5.2-7. The 54-EFPY 1/4T fluence is used to calculate the ARTs and the upper-shelf energy (USE) decrease for the beltline materials.

The methodology used by SNC/Hatch to calculate neutron fluence complies with the requirements of Regulatory Guide 1.190 [(35)(36)(37)(38)(39)(40)].

5.2.4.2.1 ART Versus EFPYs

Each beltline plate and weld ΔRT_{NDT} value is determined by multiplying the CF from RG 1.99, Rev 2, determined for the Cu-Ni content of the material, by the fluence factor for the EFPYs being evaluated. The initial RT_{NDT}, ΔRT_{NDT} and margin are added to obtain the ART of the material. The 54-EFPY ART values for all of the beltline plates and welds are shown in table 5.2-7. The ART for the limiting beltline material in HNP-1 and HNP-2 is lower than the 200°F requirements of 10 CFR 50, Appendix G, and RG 1.99, Rev 2.

Figure 5.2-4 shows the ART for the lower-shell longitudinal welds as a function of operating time in EFPYs. The information in figure 5.2-4 is used to adjust the beltline curves in the operating limits.

5.2.4.2.2 Upper-Shelf Energy at 54 EFPYs

Unirradiated upper-shelf data were not available for all the material heats. Due to the lack of specific pre-operational USE data, HNP-1 and HNP-2 were evaluated in GE Report "Plant Hatch Units 1 & 2 RPV Pressure Temperature Limits License Renewal Evaluation," GE-NE-B1100827-00-01,[(23)] to verify that GE Owners Group Report "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 through BWR/6 Vessels, Rev 1," NEDO-32205-A,[(15)] margin analyses are applicable. The equivalent margin analyses demonstrate that the 10 CFR 50, Appendix G safety requirements are satisfactorily met for HNP-1 and 2. The NRC approved NEDO-32205-A[(15)] on December 8, 1993. The NEDO analysis meets the definition of a time-limited aging analysis (TLAA) pursuant to 10 CFR 54.3. (See section 18.5 for further information.)

5.2.4.3 Pressure-Temperature Curves

As stated previously, 10 CFR 50, Appendix G, requires P/T limits for three categories of operation listed in paragraph 5.2.4.1. The heat transfer characteristics for these three categories are:

- Isothermal conditions for the hydrostatic test (curve A).
- Insulated outside surface and metal temperature equaling the fluid temperature for 100°F/h heatup/cooldown thermal rate (curves B and C).

Heat transfer characteristics for the other transient conditions were based upon flow and temperature conditions in the thermal cycle diagrams. The condition that results in the highest required temperature for the limiting material determines the minimum allowable RPV temperature.

The following four vessel regions defined in the thermal cycle diagram should be monitored against the P-T curve operating limits:

- Core beltline.
- Closure flange.
- Upper vessel.
- Lower vessel.

The core beltline is the vessel location adjacent to the active fuel such that the neutron fluence is sufficient to cause a significant shift of $RT_{NDT.}$ The closure flange region, which is discussed in detail in paragraph 5.2.4.3.2, includes the bolts, top head flange, vessel flange, and adjacent plates and welds. The remaining portion of the vessel (i.e., upper vessel and lower vessel) includes the shells; components such as the nozzles; support skirt; and stabilizer brackets.

Non-beltline regions are defined as the vessel locations that are remote from the active fuel and where the neutron fluence is not sufficient to cause any significant shift of $RT_{NDT.}$ Non-beltline components include most nozzles, the closure flanges, some shell plates, the top and bottom head plates and the control rod drive (CRD) penetrations. The limiting BWR/4 components are the feedwater nozzle and the CRD penetration (bottom head). All other components in the non-beltline regions are categorized under one of these two components.

Under certain conditions, the minimum bottom head temperature can be significantly cooler than the beltline or closure flange region. These conditions can occur when the recirculation pumps are operating at low speed or are turned off, and during water injection through the CRDs. To account for these circumstances, individual temperature limits for the bottom head were established. Bottom head curves are not provided for the core critical curve, since during core critical operation, the entire RPV follows the steam saturation curve that is well to the right of the core critical curve.

The P-T curves for the heatup and cooldown operating conditions at a given EFPY apply for both the 1/4T and 3/4T locations. When combining pressure and thermal stresses, it is usually necessary to evaluate stresses at the 1/4T location (inside surface flaw) and the 3/4T location (outside surface flaw), because the thermal gradient tensile stress of interest is in the inner wall during cooldown and in the outer wall during heatup. However, as a conservative simplification, the thermal gradient stress at 1/4T is assumed to be tensile for both heatup and cooldown. This results in the approach of applying the maximum tensile stress at the 1/4T location. This approach is conservative for two reasons:

1. The maximum stress is used regardless of flaw location.

2. The irradiation effects cause the allowable toughness, K_{IR}, at 1/4T to be less than that at 3/4T for a given metal temperature. This approach causes no operational difficulties, since the BWR vessel metal temperature is at steam saturation conditions during normal operation, satisfying the heatup/cooldown curve limits.

Three vessel regions affect the operating limits:

- Core beltline.

- Non-beltline.

- Closure flange.

The beltline region minimum temperature limits are adjusted to account for vessel irradiation. The closure flange region limits are controlling at lower pressures primarily because of 10 CFR 50, Appendix G, requirements.

5.2.4.3.1 54 EFPY P-T Curve Evaluation Using Methodology of 10 CFR 50, Appendix G, with Allowance of Code Cases N-588 and N-640

GE report GE-NE-B1100827-00-01[23] developed P-T curves in accordance with the 1989 ASME Code, Section XI, Appendix G; 10 CFR 50, Appendix G; and Welding Research Council Bulletin 175. The analysis performed for the original license term met the definition of a TLAA pursuant to 10 CFR 54.3. (See subsections 18.1.1 and 18.1.3, and section 18.5 for further information.)

Detailed stress analyses of the non-beltline components were performed for a BWR/6 plant specifically for the purpose of fracture toughness analysis. The analysis was considered appropriate for HNP-1 and HNP-2 since the plant-specific geometric values are bounded by the generic analysis. The generic value was adapted to the conditions at HNP-1 and HNP- 2 by using plant-specific RT_{NDT} values for the RPV. The analyses took into account all mechanical loading and anticipated thermal transients. Transients considered include:

- 100°F/h startup and shutdown.

- Scram.

- Loss of feedwater heaters or flow.
- Loss of recirculation pump flow.
- All transients involving emergency core cooling injections.

Primary membrane and bending stresses, and secondary membrane and bending stresses due to the most severe of these transients were used according to the ASME Code to develop plots of allowable pressure (P) versus temperature relative to the reference temperature ($T - RT_{NDT}$). Plots were developed for the limiting BWR/4 components; i.e., the feedwater nozzle and the CRD penetration (bottom head). The non-beltline curves were shifted based upon the most limiting initial RT_{NDT} values for the appropriate non-beltline components.

RT_{NDT} estimates were developed for the RPV materials in accordance with RG 1.99, Rev 2, for the different EFPY levels (table 5.2-10, sheets 1 and 2, for HNP-1 and HNP-2, respectively). The inputs used for the calculations were based upon table 5.2-7. The fluence estimates account for a rated thermal power (RTP) of 2804 MWt and reactor operating pressure increase to 1060 psia.(33) (34)

Structural Integrity Associates in "Structural Integrity Report SIR-00-037, Revised Pressure-Temperature Curves for Plant Hatch," (24) developed the current HNP 1 and HNP-2 P/T curves using the same methodology contained in GE report "Plant Hatch Units 1 & 2 RPV Pressure Temperature Limits License Renewal Evaluation," (23) modified to incorporate the methodology specified in ASME Code Cases N-588(25) and N-640(26).

The current P-T curve methodology includes the following:

1. K_{IC} was used in place of K_{IA} in accordance with Code Case N-640:

$$K_{IC} = 20.734\, e^{[0.02(T-ART_{NDT})]} + 33.2$$

where:

T	=	metal temperature at assumed flaw tip (°F).
	=	conservatively set equal to the fluid temperature.
ART_{NDT}	=	adjusted reference temperature for location under consideration and desired EFPY (°F).
K_{IC}	=	critical stress intensity factor (ksi√in.). (Note that a maximum value of 200 ksi√in. is allowed per reference 21.)

2. For the beltline region, the thermal stress intensity factor, K_{IT}, was calculated for a cooldown transient in accordance with ASME Code Case N-588:

$$K_{IT} = 9.53\text{x}10^{-4}\ CR\ t^{2\ 5}$$

where:

K_{IT} = thermal stress intensity factor (ksi√in.).

CR = transient cooldown rate (°F/h).

T = vessel wall thickness (in.).

3. For the beltline region, the allowable pressure, P, was calculated in accordance with ASME Code Case N-588 for an inside surface axial flaw:

$$Kip = M_m \sigma_m$$

where:

K_{IT} = membrane stress correction factor.

σ_m = membrane-stress due to pressure (ksi).
= PR/t.

P = pressure (ksi).

R = vessel radius (in.).

t = vessel wall thickness (in.).

Thus, $P = K_{IP}t/(RM_m)$

Note that Code Case N-588 is not applicable for the bottom head or upper vessel region, since the stress intensity factor relationships are for shells and heads remote from discontinuities.

All other aspects of the methodology detailed in reference 23 were maintained for the current P-T curves. The resulting P-T curves relate the minimum required reactor metal temperature to the RPV pressure.

5.2.4.3.2 Closure Flange Region

10 CFR 50, Appendix G, sets several minimum requirements for pressure and temperature in addition to those outlined in the ASME Code, based upon the closure flange region RT_{NDT}. In some cases, analysis results for other regions exceed these requirements, and closure flange limits do not affect the shape of the P-T curves. However, some closure flange requirements do impact the curves; e.g., HNP-1 and HNP-2 at low pressures.

The original ASME Code requirement for bolt-up was at qualification temperature (T_{30L}) plus 60°F. The Code used for the currently licensed P-T curves is the 1989 ASME Code, no addenda. The ASME Code requirements state in Paragraph G-2222(c) that, for application of full-bolt preload and RPV pressure up to 20% of hydrostatic test pressure, the RPV metal

temperature must be at RT_{NDT} or greater. The approach used for HNP-1 and HNP-2 for the bolt-up temperature was based upon a more conservative value of (RT_{NDT} + 60), or the LST of the bolting materials, whichever is greater. The 60°F adder is included for two reasons:

1. The pre-1971 requirements of ASME Code, Section III, Subsection NA, Appendix G, included the 60°F adder.

2. Inclusion of the additional 60°F requirement above the RT_{NDT} provides the additional assurance that a flaw size between 0.1 and 0.24 in. is acceptable.

The limiting initial RT_{NDT} values for the closure flange region were 16°F for HNP-1 and 30°F for HNP-2 due to the flange, upper vessel and top head plate materials The LST of the closure studs was 70°F for both units; therefore, the bolt-up temperature values used were 76°F (HNP-1) and 90°F (HNP-2). This conservatism is appropriate, because bolt-up is one of the more limiting operating conditions (high stress and low temperature) for brittle fracture.

10 CFR 50, Appendix G, Paragraph IV.A.2, including Table 1, sets minimum temperature requirements for pressure above 20% hydrostatic test pressure based upon the RT_{NDT} of the closure region. Curve A temperature must be no less than (RT_{NDT} + 90°F), while Curve B temperature must be no less than (RT_{NDT} + 120°F).

For pressures below 20% of preservice hydrostatic test pressure (312 psig) and with full-bolt preload, the closure flange region metal temperature is required to be at RT_{NDT} or greater as described above. At low pressure, the ASME Code allows the beltline and bottom head regions to experience even lower metal temperatures than the flange region RT_{NDT}. However, temperatures should not be permitted to be lower than 68°F for the reason discussed below.

The shutdown margin, provided in the HNP-1 and HNP-2 Technical Specifications, is calculated for a water temperature of greater than or equal to 68°F, corresponding to the most reactive state. Shutdown margin is the quantity of reactivity needed for a reactor core to reach criticality with the strongest-worth control rod fully withdrawn and all other control rods fully inserted. Although it may be possible to safely allow the water temperature to fall below this 68°F limit, further extensive calculations would be required to justify a lower temperature. The 76°F (HNP-1) and 90°F (HNP-2) limits apply when the head is on and tensioned, and the 68°F limit applies when the head is off while fuel is in the vessel.

5.2.4.3.3 Core Critical Operation

The core critical operation curve (Curve C) is generated based upon the requirements of 10 CFR 50, Appendix G, Table 1, which requires that core critical P-T limits be 40°F above any Curve A or B limits when pressure exceeds 20% of the preservice system hydrostatic test pressure. Curve B is more limiting than Curve A; therefore, limiting Curve C values are at least Curve B plus 40°F for pressures above 312 psig.

Table 1 indicates that for a BWR with water level within normal range for power operation, the allowed temperature for initial criticality at the closure flange region is (RT_{NDT} + 60°F) at pressures below 312 psig. This requirement results in the minimum criticality temperatures of

76°F (HNP-1) and 90°F (HNP-2), based upon RT_{NDT} values of 16°F and 30°F for HNP-1 and HNP-2, respectively. In addition, above 312 psig, the Curve C temperature must be at least the greater of RT_{NDT} of the closure region + 160°F or the temperature required for the hydrostatic pressure test (Curve A at 1105 psig). Therefore, this requirement causes a temperature shift in Curve C at 312 psig.

Operating Limits Versus Operating Conditions

Comparison of the pressure versus temperature limits in HNP-1 and 2 Technical Specification 3.4, with operating conditions for the most severe upset transient, shows the limits will not be exceeded during the design life of the vessel. Reactor operating procedures were established such that actual transients will not be more severe than those for which the vessel design adequacy has been demonstrated. Of the design transients, the upset condition producing the most adverse temperature and pressure condition anywhere in the vessel yields a minimum fluid temperature of 250°F in the bottom head and a maximum pressure peak of 1180 psig. A scram automatically occurs with initiation of this upset condition. For a temperature of 250°F, the maximum allowable pressure exceeds 1180 psig for the intended margin against nonductile failure. The maximum transient pressure of 1180 psig is, therefore, within the specified allowable limits.

5.2.4.4 Compliance With 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements

Charpy impact specimens for the reactor vessel material surveillance program are of the longitudinal orientation consistent with the ASME requirements prior to the issue of the summer 1972 addenda and American Society for Testing and Materials (ASTM) E 185-73. Based on BWR operating experience, the amount of shift measured by these irradiated longitudinal test specimens is essentially the same as shift in an equivalent transverse specimen. The program includes three sets of specimens in the reactor. The specimens are manufactured from a plate actually used in the beltline region and a weld typical of those in the beltline region and thus represent base metal, weld metal, and the transition zone between base metal and weld.

Sufficient tensile and CVN specimens are provided in each of the three in-reactor sets and in the out-of-reactor set to measure strength, ductility, and toughness of each of the three materials (base, weld, heat affected zone), both in the unirradiated and irradiated conditions. In total, the program consists of 84 impact and 24 tensile specimens. In addition, there are 72 impact and 12 tensile archive and spare specimens.

The reactor vessel surveillance program specimens in HNP-2 meet the requirements of 10 CFR 50, Appendix H, and ASTM E 185-73, except for the following:

A. The plate material is from the beltline material but was chosen at random from the three beltline plates rather than in accordance with E 185-73. The weld material is typical of the beltline welds but was not used in the beltline.

B. The base metal specimens are longitudinal.

C. Two of the three groups of impact specimens are in sets of 8 rather than sets of 12 specimens.

It is General Electric's technical judgment that none of these three variations affect the value of data from these specimens.

The Plant Hatch schedule for removal of the Unit 2 surveillance capsule is given by the integrated surveillance program (ISP) and is provided in table 5.2-3.

This program was developed by the BWR Vessel and Internals Project in 1998. The ISP combines all the participating US BWR surveillance programs into a single integrated program and adds data from a supplemental surveillance program (SSP). The ISP has been designed to meet the criteria for an integrated surveillance program in 10 CFR 50 Appendix H.

A matrix of capsules containing the representative weld and plate materials and the planned schedules for withdrawing and testing is provided in table 5.2-11. The overall ISP, as documented in references 28 through 32, replaces the existing material and surveillance monitoring programs with an integrated program using host reactor capsules containing the selected materials.

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

5.2.4.4.1 Positioning of Surveillance Capsules

The sealed capsules are not attached to the vessel but are in welded capsule holders. The capsule holders are mechanically retained by capsule brackets welded to the vessel cladding. The capsule holder brackets allow the capsule holder to be removed at any desired time in the life of the plant for specimen testing. These brackets are designed, fabricated, and analyzed to the requirements of Section III of the ASME Code.

5.2.4.4.2 Time and Number of Dosimetry Measurements

Separate neutron dosimeters were provided so that fluence measurements could be made at the vessel ID during the first fuel cycle to verify the predicted fluence at an early date in plant operation. Dosimetry is also available in each surveillance capsule to measure flux over longer operating periods and evaluate effects of changing core power distribution, if any.

5.2.4.5 <u>Reactor Pressure Vessel Annealing</u>

Inplace annealing of the RPV because of radiation embrittlement is not necessary, since shifts in transition temperature and USE values are within the allowables of 10 CFR 50, Appendix G.

5.2.5 AUSTENITIC STAINLESS STEEL

5.2.5.1 Cleaning and Contamination Protection Procedures

During fabrication, the stainless steel surfaces were cleaned by mechanical methods (grinding, brushing with stainless steel brushes, machining), solvent cleaners, or chemical cleaning agents. Caustic cleaners and other solvents and cleaners containing halogens, sulphides, or other harmful constituents were not used for cleaning parts that contain crevices or entrapment areas.

Stainless steel materials were not pickled unless they were in the solution heat-treated condition. Stainless steel components were suitably packaged and protected during shipment, storage, and construction to prevent contamination from potential corrosive agents. The reactor vessel or vessel parts containing stainless steel components were not stored outside without full protection to prevent rainwater or condensate moisture from washing or collecting on stainless surfaces.

Immediately prior to hydrostatic testing of the reactor vessel, all interior surfaces that would contact water during the hydrostatic test, all nozzle fixtures, all piping to be used to fill the vessel, and all external surfaces of stainless and nickel-chrome-iron components were cleaned of all halogen bearing soils, grease, oil, penetrant materials, inks, chalk or crayon marks, and all dirt and debris. Testing and operation of components and systems were performed using either inhibited water or high-purity demineralized water to avoid exposure to detrimental contaminants.

All loose dirt and other foreign materials were removed by sweeping or vacuuming. Deposits of grease and oil were removed with an approved solvent. Tightly adhering soils were removed with the aid of stainless steel brushes or by grinding. The vessel interior was then cleaned with high-pressure potable water containing corrosion-inhibiting additives. The vessel and water temperature was < 180°F during the cleaning step, the water pressure was a minimum of 6,000 psi, and the water contained < 35 ppm chlorides, 10 ppm fluorides, and 1 ppm sulfides.

The cleanliness of the vessel was checked visually and with the aid of an ultraviolet light to ensure the vessel was clean. The ultraviolet examination was conducted under darkened conditions with a lamp providing a minimum intensity of 100 fc. All fluorescent materials were removed from the surface. All plumbing, welding, or testing work was performed prior to cleaning. During any entry of personnel into the vessel after cleaning was completed, shoe covers were worn and clean conditions were maintained in the reactor vessel.

5.2.5.2 Solution Heat Treatment Requirements

Replaced recirculation piping, stainless steel portions of RHR, and replaced portions of RWC piping are solution annealed by heating to a temperature between 1900 and 2000°F (metal temperature) and are held at this temperature for a minimum of 15 min with a maximum time at temperature of 30 min. This is followed by quenching in water to a temperature below 800°F within 3 min following the heating.

Replaced recirculation, RHR, and RWC fittings and subassemblies are solution annealed by heating to a temperature between 1900 and 2100°F (metal temperature) and are held at this

temperature for a minimum of 15 min/in. of thickness but not < 15 min regardless of thickness. This is followed by quenching in water to a temperature below 800°F within 3 min following the heating.

Solution heat treatment of other austenitic stainless steel consisted of heating the material to 1900 to 2100°F, holding for 1/2 h/in. of thickness (minimum 1/2 h) and quenching in water to below 800°F. Nickel-chrome-iron alloys, which may have been subjected to temperatures in excess of 1700°F exclusive of welding, were rechecked for grain size (for information) and specified mechanical properties (for acceptance).

5.2.5.3 Material Inspection Program

The raw material inspection program used to verify that the unstabilized austenitic stainless steels were properly solution heat treated and not susceptible to intergranular attack is as follows:

A. *For replaced recirculation system piping following solution heat treatment and pickling, material representatives of every heat treat lot were tested for sensitization by a modified version of ASTM A 262, Practice A and examined for intergranular attack.*

B. *For other austenitic stainless steel components, no testing was required if valid documentation was furnished proving that the stainless steel had been given a suitable water quench from a temperature above 1800°F, and no subsequent heating had been employed.*

C. *If documentation to verify adequate water quenching was not available, the material was required to be tested in accordance with ASTM A 262, Practice E.*

5.2.5.4 Unstabilized Austenitic Stainless Steels

The unstabilized grades of austenitic stainless steels with a carbon content > 0.03% used for RCPBs are Types 304 and 316.

5.2.5.5 Avoidance of Sensitization

Wrought and cast austenitic stainless steels used for the reactor vessel system (except for vessel cladding) were supplied in the solution heat-treated condition and, thereafter were not subjected to any heating above 800°F, except for welding or resolution heat treatment.

Sensitization of wrought austenitic stainless steel was avoided for piping and RCPB pumps and valves. Austenitic stainless steel was considered to be severely sensitized if it was heated by means other than welding within the range of 800°F to 1800°F, regardless of a subsequent cooling rate. Such stainless steel was required to either pass the requirements of ASTM A 262, Practice E, or be resolution heat treated. When heated above 1800°F, the austenitic stainless steel was required to be rapidly cooled through the range 1800°F to below 800°F by water

quench to produce an acceptable grain structure. Where severe sensitization could not be avoided, such as for parts which were required to be hard surfaced, low carbon, type 304 cast material was used.

5.2.5.5.1 Welding Controls

During stainless steel welding, the interpass temperature is controlled to a maximum of 350°F. Weld layers are built up uniformly along the joint and across the width of the joint. Block welding is not permitted, and weld stops and starts are staggered. Welds are cleaned free of slag, flux, and other foreign material prior to depositing subsequent beads.

Austenitic stainless steel filler metal for seam welds of recirculation piping, stainless steel portions of RHR, and replaced portions of RWC components were required to contain 5 FN (Ferrite Number) in the undiluted weld deposit. For butt welds and attachment welds that would not subsequently be solution heat treated, the filler metal was required to contain 8.0 FN in the undiluted weld deposit. Other austenitic weld materials are selected and controlled to produce welds which contain a minimum of 3% ferrite. Ferrite content is determined by one of the following methods:

- Actual chemical analysis compared to the Schaeffler and Schoeffer analysis.
- Magne gauge.
- Metallography.
- Severn gauge.
- Ferrite scope.

5.2.5.6 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitizing Temperatures

Welding procedures require control of heat input to avoid severe sensitization and susceptibility to intergranular attack. No retesting of as-welded unstabilized austenitic stainless steel is required or planned.

Unstabilized austenitic stainless steel subjected to heat in the range of 800°F to 1500°F by any means other than welding is required to be retested in accordance with ASTM A 262, Practice E.

5.2.5.7 Control of Delta Ferrite

The procedures and requirements used for the control of delta ferrite in austenitic stainless steel welds are discussed in paragraph 5.2.5.5.

5.2.6 PUMP FLYWHEELS

Pumps with flywheels are not used in HNP-2.

5.2.7 REACTOR COOLANT PRESSURE BOUNDARY LEAK DETECTION SYSTEM

5.2.7.1 Design Bases

The LDS is designed to:

- Detect the occurrence of, and alert operating personnel to, abnormal leakage from the RCPB.
- Detect leakage in the vicinity of the ECCS pumps and pump suction piping.
- Detect leakage from the nuclear process barrier at selected locations outside the primary containment.

5.2.7.2 Leak Detection Methods

The RCPB LDS consists of temperature, pressure, flow, and fission-product sensors with associated instrumentation and alarms. This system detects and annunciates abnormal leakage in the following systems:

- Main steam.
- RWC.
- RHR.
- RCIC.
- Reactor feedwater.
- HPCI.
- Reactor recirculation.

A summary of isolation and/or alarms of affected systems and the methods used appears in table 5.2-8.

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

5.2.7.2.1 Detection of Abnormal Leakage Within the Primary Containment

Leaks within the primary containment are detected by monitoring for:

- Abnormally high pressure and temperature within the primary containment.
- Rapid fillup and/or slow pump-down of equipment and floor drain sumps.
- Excessive temperature difference between the inlet and outlet cooling water for the primary containment equipment coolers.
- A decrease in the RPV water level.
- Changes in hydrogen and oxygen concentration (subsection 6.2.5).
- High flowrate in process lines.
- High particulate and gaseous radiation levels in the primary containment atmosphere.

Temperatures within the primary containment are monitored at various elevations. (Also, the temperature of the air to the atmosphere coolers is monitored.) Excessive temperature in the primary containment, increased drain sump activity, and increased fission product radiation level are annunciated by alarms in the MCR. RPV water levels 2 and 3 and high drywell pressure are annunciated by alarms in the MCR and cause automatic isolation of the containment. In addition, RPV water level 1 isolates the main steam lines and the main steam line drain and reactor water sample valves.

The systems within the drywell share a common area; therefore, their LDSs are common. Each LDS inside the drywell is designed with a capability of detecting leakage less than established leakage rate limits.

5.2.7.2.2 Leak Detection

The drywell floor drain sump measurement monitors the normal design leakage collected in the floor drain sump. This leakage consists of leakage from the CRDs, valve flange leakage, closed cooling water, air cooler drains, and any leakage not connected to the equipment drain sump.

Leakage from the RCPB inside the drywell may be detected by any one of a variety of independent monitored variables, such as drywell pressure and temperature, sump level changes, and containment gaseous and particulate radioactivity levels. While some of these systems are not redundant in themselves, it is not postulated that any one event could render all means of leak detection inoperable.

The normal operational method for monitoring leakage in the drywell is with the drywell floor drain sump LDS. The Technical Specifications require the drywell floor drain sump LDS to be operable whenever the plant is operating.

The drywell equipment drain sump measurement monitors identified leakage collected in the equipment drain sump. The sump receives condensate drainage from pump seal leakoff. Collection in excess of background leakage would indicate reactor coolant leakage. Equipment sump drain temperature is also monitored and thus will indicate leakage.

Leakage from various equipment located in the drywell is piped directly to the drywell equipment drain sump. The sump itself is covered and all of the various drain lines are open only to the equipment they serve, thereby forming a closed system which receives leakage only from identified sources.

The drywell floor drain and equipment drain sumps are provided with redundant level transmitters that supply remote level indications. The level indicators are equipped with switches that start and stop the pumps as required and provide signals to the LDS.
The LDSs have two timers that are energized and deenergized by the sump level switches to determine if the leakage rate into the sump is in excess of the expected design value. One timer is started each time the sump is pumped down to the low-level setpoint, at which time the sump pumps are automatically stopped. Should the sump fill up to the high-level setpoint (automatically starting the sump pumps) prior to the expiration of time on the timer, an alarm is sounded in the MCR indicating a leakage rate into the sump in excess of the design limit.

A second timer is started when the sump pumps are started on high level. Should this timer run out prior to the sump level reaching the low-level pump cutoff setpoint, an alarm is sounded in the MCR indicating a leakage rate into the sump in excess of the design limit.

Additionally, a flow indicator is installed in the discharge of the drywell equipment sump pumps which provides sump pump flow indication in the MCR.

The drywell floor drain sump has a smaller volume than the drywell equipment drain sump to provide for a more rapid response to the LDS for unidentified leakage. All drains inside the drywell empty into one of these two sumps, and since unidentified leakage is excluded from the drywell equipment drain sump, both identified and unidentified leakage can be quantified.

In the operating range of sump level, the relationship between leakage and level is 13 gal/in. for the floor drain and 22 1/2 gal/in. for the equipment drain. All leakage inside the drywell will flow directly either to the floor drain or to equipment drain sumps, depending on the source of leakage. As shown on drawing no. H-26202, the drywell floor is provided with floor drain fittings spaced uniformly around the reactor vessel pedestal which drain directly to the floor drain sump. The drywell floor is finished such that these floor drain fittings are located at the low points. The

floor drain sump, located inside the reactor vessel pedestal, is provided with a grated cover so that any leakage in that area will flow directly into the sump.

There are no reservoirs in the drywell which could retain enough leakage to prevent the actuation of the LDS.

Drawing no. H-26202 shows the drywell floor arrangement and the locations and elevations of the drywell sumps and instrumentation used for leak detection. Level transmitters 2G11-N074 A and B and N075 A and B are the only components of the drywell LDS actually located inside the drywell. The remainder of the equipment is located in the reactor building and the MCR.

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

The drywell cooling system recirculates the primary containment atmosphere through heat exchangers (air coolers) to maintain the primary containment at its average operating temperature of 135°F. The drywell average air temperature limit for normal operation is ≤ 150°F. The primary containment chilled water system provides cooling water to the air coolers. An increase in primary containment atmosphere temperature would increase the temperature rise in the cooling water passing through the coils of the air coolers. Thus, the temperature difference increase between inlet and outlet to the air coolers indicates the presence of a reactor coolant or steam leakage. Also, a drywell ambient temperature rise above normal may indicate the presence of reactor coolant or steam leakage.

Radiation monitoring of the primary containment is provided as required by Criterion 64 of 10 CFR 50, Appendix A, and Regulatory Guide 1.45, (May 1973), as clarified in Appendix A, Regulatory Guide Evaluations. The post-accident radiation monitoring system (RMS) is part of the redundant LDS. Information from this system is used in conjunction with the drywell floor drain sump level indicating system. It is provided to improve the total drywell LDS diversity and sensitivity. The design basis, the associated instrumentation, and maintenance requirements for the leak detection RMS are presented in section 11.4. The post-accident radiation monitors discussed in paragraph 11.4.2.8.12 are redundant, qualified Seismic Category I, and would be available to detect coolant leakage should the drywell sump LDS become inoperable, thus assuring the capability of the LDS to detect unidentified leakage.

Since most of the parameters listed in table 5.2-8 are not a true measurement of leakage but rather a certain indication that would be expected to accompany a fluid system leak, there is not a direct correlation in each case between leakage rate and the monitoring system indication.

The containment atmosphere fission product monitors and the post-accident radiation monitors are capable of detecting leakage from the RCPB.

The equipment area temperature and high differential temperature alarms are set at the lowest temperature consistent with normal operational variations in order to provide early indication of a possible leak. These alarms and their setpoints are discussed in subsection 7.6.9

5.2.7.2.2.1 Reactor Vessel Head Seal Leak Detection. The RPV head is provided with double seals with a pressure switch sensing the pressure between the seals. High pressure is indicative of leakage past the inner seal and activates an annunciator in the MCR. Leakoff between the seals is piped to the equipment drain sump.

5.2.7.2.2.2 Recirculation Pump Seal Leak Detection. There are two recirculation pump LDSs, one for each of the pumps in the recirculation loop. Each LDS monitors the flowrate (leakage) past its associated pump's shaft by measuring the pressure within the seal cavity. There are two monitored seal cavities per pump.

The recirculation pump LDS consists of two types of monitoring circuits. The first of these monitors the pressure levels within the seal cavities, presenting the plant operator with a visual display of the pressure in each cavity. The second type of circuit monitors the rate of liquid flow from the seal cavities. The pressure levels within seal cavity no. 1 and seal cavity no. 2 are measured with identical instrumentation.

All condensate flowing past the recirculation pump seal packings and into the seal cavities is collected and sent by one of two drain systems to the drywell equipment drain sump for disposal. The first system drains the major portion of the condensate collected within the no. 2 seal cavity. The condensate flowrate through the drain system is measured (high/low) by a flow switch. The point at which the microswitch closes can be adjusted so that switch actuation occurs only above or below certain flowrates. Excessively high or low flowrates through this drain system activate the pump seal staging flow annunciator in the MCR.

5.2.7.2.2.3 Safety Relief Valve (ADS) Leak Detection. A temperature element (sensor) is used to detect leakage past each safety relief valve. These temperatures are recorded on a multipoint recorder in the MCR. Normally, all safety relief valves are in the shut-tight condition and remain at about the same temperature.

Steam passage through the valve elevates the sensed temperature at the exhaust, causing an abnormal temperature reading on the recorder. Microswitch contacts on the recorder close on high temperature to activate the safety/blowdown valve leaking annunciator in the MCR.

5.2.7.2.3 Detection of Abnormal Leakage Outside the Primary Containment

Outside the primary containment, the piping within each system monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each LDS discussed below is designed to detect leak rates that are less than the established leakage limits. The method used to monitor for leakage for each RCPB component is shown in table 5.2-8.

5.2.7.2.3.1 ECCS Suction Lines Leak Detection. The purpose of this LDS is to provide information which would allow the closing of the valve in a broken ECCS suction line.

A description of the LDS employed is presented in subsection 9.3.3.

5.2.7.2.3.2 **Reactor Building Sump Flow Measurement.** A description of the reactor building sump flow measurement system utilized for leakage detection is discussed in subsection 9.3.3.

5.2.7.2.3.3 **Visual and Audible Inspection.** Accessible areas are inspected periodically. The temperature and flow indicators discussed above are monitored regularly. Any instrument indication of abnormal leakage is investigated.

5.2.7.2.3.4 **Reactor Water Cleanup System Leak Detection.** Leakage in the high temperature process flow of the RWC system external to the primary containment is detected by temperature-sensing elements. The RWC rooms are maintained at a negative pressure. Resistance temperature detectors (RTDs) are located near the entrances to the rooms and inside the rooms to measure temperature differential. RTDs are also located to measure the inlet and outlet air temperature differential of the RWC pump and heat exchanger area cooling unit. Local ambient temperature is also sensed by one of these RTDs. Cables are routed from these RTDs to the trip units in the MCR. A high cleanup room temperature rise or a differential temperature rise actuates automatic isolation of the RWC system.

The RTDs and associated trip units are part of the analog transmitter trip system (ATTS), which is described in section 7.8.

In addition, thermocouple-type sensors located near the RTDs are coupled with temperature switches and an indicating recorder in the MCR. Alarms in the MCR annunciate a temperature rise corresponding to excessive leakage.

In addition to the temperature detection method, leakage is detected by means of a flow comparison between RWC system inlet and outlet. If the inlet flow exceeds outlet flow by at least 79 gal/min for more than 45 s, an alarm is actuated, and the RWC system is isolated automatically. However, this differential flow monitoring of the RWC system leakage detection is not required to mitigate a design basis event.

5.2.7.2.3.5 **Main Steam Line Leak Detection Outside Primary Containment.** The main steam lines are continuously monitored for leaks by the main steam line LDS. Steam line leaks will cause changes in at least one of the following monitored operating parameters:

- Sensed temperature.
- Flowrate.
- Low water level in the RPV.

If a leak is detected, the detection system responds by triggering an annunciator in the MCR and, depending upon the activating parameter, initiates steam line isolation action.

The temperature around the main steam line is monitored by RTDs placed along the main steam line piping in the main steam pipe chase. Cables are routed from these RTDs to trip units in the MCR. The contacts of each set of trip units are wired for coincidence closure of the MSIVs on high temperature. This instrumentation is part of the ATTS, which is described in section 7.8. In addition, thermocouples are mounted at the inlet and outlet of the steam tunnel to measure the tunnel ambient and temperature difference and to alarm on temperature rise in the MCR. There are also thermocouples and temperature-indicating switches in the turbine building which sense the ambient temperature in the vicinity of the main steam lines. An excessive temperature rise isolates the main steam lines.

The flowrate monitoring components of the main steam line leak detection system consist of a set of four differential pressure transmitters and trip units for each main steam line. The outputs of the differential pressure trip units are connected to components of the nuclear steam supply shutoff system to provide the main steam line high flow signal for main steam line isolation (table 7.3-9). (The main steam line flow differential pressure relays associated with the RCIC isolation are time delay relays which prevent isolation of the RCIC on high steam line flow for a finite period after the signal has been received.)

Reactor water level and main steam line tunnel area temperature are monitored by circuits associated with the RPV and primary containment isolation system to indicate the presence of a steam leak. The coverage of this discussion extends only to the sensing instrumentation and not to circuit arrangement or response. Such information may be found in the description of the RPV and primary containment isolation system.

Under conditions of normal reactor operation at constant power, reactor water level should remain fairly constant at its programmed level since the rate of steam mass flow leaving the boiler is matched by the feedwater mass flowrate into the RPV. However, given a condition of continued steam leakage from the closed system, the condensate reservoir level and the reactor water level decrease.

Reactor water level is monitored by four level transmitters and trip units of the containment isolation system in addition to the normal complement of process monitoring instruments. Reactor water level falling below the predetermined minimum allowable level (level 1) results in switch actuation and subsequent containment isolation system response.

5.2.7.2.3.6 Residual Heat Removal System Leak Detection. The RHR leak detection components are divided into two groups; one sensitive to RHR system leaks external to the primary containment and the other group sensitive to system leaks internal to the primary containment. Leak detection instruments of the first group utilize devices which are sensitive to temperature and which monitor area ambient and differential temperatures. The second group of instruments monitors the pressure and temperature level within the drywell. Additionally, liquid leakage from system components contained within the drywell is collected, and the rate of accumulation is measured. The ambient and differential temperature monitoring circuits consist of thermocouples, 36 temperature switch point modules, 2 selector switches, and 2 meters. Of

the 36 monitored signals available, only 4 are from the RHR system. The other 32 are used to monitor temperatures of other reactor subsystems.

The thermocouples are mounted in their individual holders which, in turn, are mounted in the RHR equipment area such that they are sensitive primarily to the air temperature. The four-point modules, the selector switches, meter modules, and meters are mounted on the leak detection panel in the MCR. A high ambient temperature lights the point module alarm indicator on the leak detection panel and sounds the high ambient temperature alarm.

5.2.7.2.3.7 <u>Reactor Core Isolation Cooling and High-Pressure Coolant Injection Systems</u>. Leaks in the RCIC or HPCI systems are detected by differential pressure transmitters and trip units and by local temperature detectors which are functionally the same as those described for main steam line leak detection.

Downstream of the differential pressure elements, gross leaks in the system are detected by a set of two differential pressure transmitter and trip units sensing differential pressure across an elbow. Flow in excess of specified limits isolates the system and activates an alarm in the MCR. Gross leaks upstream of the differential pressure elements may be picked up by a set of four pressure transmitter and trip units. The primary function of these trip units is to detect low reactor pressure and to provide HPCI or RCIC turbine isolation signal.

The turbine exhaust vent lines of the HPCI system and the RCIC system are monitored for pressure by means of four pressure transmitter and trip units. A high-pressure signal isolates the system and activates an alarm in the MCR. Temperature sensors are located in the inlet to emergency coolers for measuring room ambient temperature in the event of steam leakage. High temperature is annunciated in the MCR and isolates the system.

The power required to operate the timer logics associated with the RCIC and HPCI LDSs is continuously monitored. Loss of power is identified by the RCIC logic power failure or HPCI logic power failure annunciators in the MCR.

Temperature elements are also located near the inlet and outlet of the ventilation ducts of the suppression pool area and near the steam lines. High differential temperature between the inlet and outlet ventilation ducts or high ambient temperature near the steam lines is annunciated in the MCR and actuates a timer. Timer actuation notification is provided by a separate MCR annunciator. This annunciator will notify the operator of possible system isolation. If the temperature rise is not reduced before the timer has run out, the RCIC and HPCI systems are isolated automatically. The alarm and the timer are activated by the temperature rise corresponding to steam leakage. Once the alarm is actuated, manual isolation of the system is permitted.

The LDS instrumentation is part of the ATTS, which is described in section 7.8.

5.2.7.2.3.8 <u>Feedwater Leak Detection</u>. A separate feedwater LDS is not provided. Leaks from the feedwater lines will be detected by one or a combination of the following methods:

- Primary containment sumps high flowrate.
- Primary containment air cooler cooling water high temperature differential.
- Primary containment high pressure.
- Primary containment high temperatures.
- Reactor building sump high flowrate.

5.2.7.3 Indication in Main Control Room

Details of the LDS indications are included in paragraph 5.2.7.2, subsection 7.6.9, and section 7.8.

5.2.7.4 Limits for Reactor Coolant Leakage

5.2.7.4.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the RCIC systems and is independent of the reactor feedwater system, normal ac power, and the ECCS. The total leakage rate limit is established at 30 gal/min averaged over any 24-h period.

The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps. The equipment drain sump and the floor drain sump, which collect all leakage, are each drained by two 100-gal/min pumps. The total leakage rate limit for both sumps of 30 gal/min is set below the removal capacity of one pump in each sump.

5.2.7.4.2 Identified Leakage

The pump packing glands, valve stems, and other seals in systems that are part of the nuclear system process barrier and from which a normal design leakage less than the 25 gal/min limit is expected are provided with drains or auxiliary sealing systems. NSSS valves and pumps inside the drywell are equipped with double seals and packings.

Leakage from the primary RRS pump seals is piped to the equipment drain sump as described in subsection 5.5.1. Leakage from the main steam line safety relief valves is identified by temperature sensors that transmit to the MCR. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage. Leakage from the RPV head flange gasket is detected by a pressure switch, as described above.

Thus, the leakage rates from pumps, valve seals, and the RPV head seal are measurable during plant operation. These leakage rates, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates.

5.2.7.5 Unidentified Leakage

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

An allowance is made for normal plant operation leakage that does not compromise barrier integrity and is not identifiable. The unidentified leakage rate limit is established at a 5-gal/min rate to allow time for corrective action before the nuclear system process barrier could be significantly compromised. This proposed limit is based on a calculated flow from a critical crack in a primary containment system pipe.

5.2.7.5.1 Sensitivity and Response Time

The LDS is able to detect unidentified leakage of 5 gal/min within 1 h.

5.2.7.5.2 Length of Through-Wall Flaw

Experiments conducted by General Electric and Battelle Memorial Institute (BMI) permit an analysis of critical crack size and crack opening displacement. This analysis is related to axially oriented through-wall cracks. (References 3 and 4 were used to develop the critical crack analysis.)

5.2.7.5.2.1 Critical Crack Length. Both the General Electric and BMI test results indicate that theoretical fracture mechanics formulas do not predict critical crack length. However, satisfactory empirical expressions may be developed to fit test results. A simple equation which fits the data in the range of normal design stresses for carbon steel pipe is:

$$\ell_c = \frac{15{,}000D}{\sigma_h} \qquad (1)$$

where:

ℓ_c = critical crack length (in.)

D = mean pipe diameter (in.)

σ_h = nominal hoop stress (psi)

Data correlation for equation 1 is shown in figure 5.2-1.

5.2.7.5.2.2 <u>Crack Opening Displacement</u>. The elasticity theory predicts a crack opening displacement of:

$$w = \frac{2\ell\sigma}{E} \tag{2}$$

where:

ℓ = crack length (in.)

σ = applied nominal stress (psi)

E = Young's modulus (psi)

Measurements of crack opening displacement made by BMI show that local yielding greatly increases the crack opening displacement as the applied stress approaches the failures stress σ_f. A suitable correction factor for elasticity effects is:

$$C = \sec\frac{\pi}{2}\frac{\sigma}{\sigma_f} \tag{3}$$

The crack opening area is given by:

$$A = C\frac{\pi}{4}w\ell = \frac{\pi\ell^2\sigma}{2E}\sec\left(\frac{\pi}{2}\frac{\sigma}{\sigma_f}\right) \tag{4}$$

For a given crack length ℓ, σ_f = 15,000 D/ℓ .

5.2.7.5.2.3 <u>Leakage Flowrate</u>. The maximum flowrate for blowdown of saturated water at 1000 psi is 55 lb/s/in.^{2}; and for saturated steam, the rate is 14.6 lb/s/in.^{2} [(5)] Friction in the flow passage reduces this rate, but for cracks leaking at 5 gal/min (0.7 lb/s), the effect of friction is small. The required leak size for a 5-gal/min flow is:

- A = 0.0126 in.^{2} (saturated water).
- A = 0.0475 in.^{2} (saturated steam).

From this mathematical model, the critical crack length and the 5-gal/min crack length have been calculated for representative BWR pipe sizes (schedule 80) and pressure (1050 psi). Results are tabulated as follows:

Nominal Pipe Size (Schedule 80) (in.)	Average Wall Thickness (in.)	5-gal/min Crack Length, ℓ, (in.)		Critical Crack Length, ℓ_c, (in.)	
		Steam Line	Water Line	Steam Line	Water Line
4	0.337	7.2	4.9	9.7	9.6
12	0.687	8.5	4.8	19.7	19.8
24	1.218	8.6	4.6	34.8	34.8

The ratios of crack length (ℓ) to the critical crack length (ℓ_c) as a function of nominal pipe size are:

Nominal Pipe Size (Schedule 80) (in.)	Ratio, ℓ/ℓ_c	
	Steam Line	Water Line
4	0.745	0.510
12	0.432	0.243
24	0.247	0.132

It is important to recognize that the failure of ductile piping with a long through-wall crack is characterized by large crack opening displacements which precede unstable rupture. Judging from observed crack behavior in the General Electric and BMI experimental programs involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gallons per minute will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1 to 0.2 in. at the time of incipient rupture, corresponding to leaks of the order of 1 in.^{2} in size for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there is insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550°F yield stress, assuming high thermal expansion stresses exist. A good mathematical model which is supported by test data is not available for the circumferential crack. Therefore, it is assumed that the longitudinal crack, subject to a stress as high as 30,000 psi, approaches worst case with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

Figure 5.2-6 shows general relationships between crack length, leak rate, stress, and line size, using the mathematical model described above. The asterisks denote conditions at which the crack opening displacement is 0.1 in., at which time instability is imminent. This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is > the 5-gal/min criterion.

5.2.7.5.3 Margins of Safety

The margins of safety for a detectable flow to assume critical size are presented in paragraph 5.2.7.5.2. Figure 5.2-6 shows general relationships between crack length, leak rate, stress and line size using the mathematical model.

5.2.7.5.4 Criteria to Evaluate Adequacy and Margin of Leak Detection System

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier located in the primary containment and reactor building (table 5.2-8). The instrumentation can be set to provide alarms at established leakage rate limits and isolate an affected system when necessary. The alarm points are determined analytically or, where appropriate, based on measurements of appropriate parameters made during startup and preoperational tests.

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

5.2.7.6 Maximum Allowable Total Leakage

The total leakage rate is presented in paragraph 5.2.7.4.1.

5.2.7.7 Differentiation Between Identified and Unidentified Leaks

Paragraph 5.2.7.2 describes the systems that are monitored by the LDS. The ability of the LDS to differentiate between identified and unidentified leakage is discussed in paragraphs 5.2.7.2 through 5.2.7.5.

5.2.7.8 Sensitivity and Operability Tests

Testability of the LDS is discussed in subsection 7.6.9.

5.2.8 PRESERVICE AND INSERVICE INSPECTION PROGRAMS

5.2.8.1 *Preservice Inspection Program*

The construction permit for the Edwin I. Hatch Nuclear Plant-Unit 2 was issued in December 1972, and as a result, the preservice inspection program was required to meet the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, through the Summer 1971 Addenda. This edition of the code does

not address inspection of Code Class 2 components. However, a commitment was made by the applicant to provide access for inspection of the Code Class 2 portions of the ECCS components. The preservice inspection program meets, to the extent practical, ASME Code, Section XI, 1974 through Summer 1975 Addenda.

5.2.8.2 Inservice Inspection Program

The inservice inspection and testing programs are described in the Edwin I. Hatch Nuclear Plant-Units 1 and 2 Inservice Inspection Program and the Edwin I. Hatch Nuclear Plant-Unit 1 and Unit 2 Inservice Testing Program. These documents describe the programs for Class 1, 2, and 3 component and piping examinations and for pump and valve surveillance testing. Nuclear Regulatory Commission approvals and exceptions are documented in these programs. It should be noted that the classification of components as ASME Class 1, 2, or 3 equivalent for inservice inspection does not imply that the components were designed in accordance with ASME requirements.

The component design codes remain as stated in the FSAR.

The inservice inspection program was augmented to satisfy guidelines of Generic Letter 88-01 and NUREG-0313, Revision 2. This is documented in submittals to the Nuclear Regulatory Commission.[9,10,11] Nuclear Regulatory Commission approvals and exceptions are documented in reference 12.

5.2.8.2.1 Class 1 RCPB Access Provisions

The ASME Section III Class 1 components of the RCPB subject to inspection are those defined in Section XI of the Code, unless excluded under IWB-1220 of Section XI.

The criteria followed to provide access in accordance with ASME Section XI for areas and components of the RCS are discussed as follows:

A. Piping Welds

Accessibility requirements for piping welds were based on providing the necessary space for ultrasonic inspection. Requirements for visual or surface inspection are less stringent and are, therefore, met by the ultrasonic access provisions. An angle about the longitudinal axis of the pipe, a length along the longitudinal axis, and a radial distance outward from the piping outside diameter were considered in determining the volume about the inspection area which must be kept free of obstructions to permit inspection.

For circumferential welds subject to surface and volumetric examination, the weld and base metal are accessible for 360 degrees about the pipe axis. The length along the longitudinal axis is a function of the piping wall thickness and the angle of the ultrasonic beam in the material.

The radial distance required outward from the piping surface was dependent on the piping diameter and on the choice of manual or automatic scanning.

The radial dimension allowed for inspection of those welds to be automatically scanned was that required for the installation, operation, and removal of the scanning device. To ensure that accessibility would be adequate for a variety of device designs, this dimension was conservatively selected for all pipe sizes. For the manual scanning operation, the radial dimension is based on allowing free movement of the operator's hand and arm about the inspection area with head access as required to allow direct visual following of all prescribed movements.

Removable insulation is provided for piping circumferential weld joints required to be inspected during the life of the plant.

Review of the high-energy fluid system piping between the first isolation valve outside the containment and the first isolation valve inside the containment reveals that all but 2 welds can be 100% volumetrically inspected, using ultrasonic inspection methods.

The RCIC steam supply piping contains a 4-in. elbow-to-penetration weld that is not 100% ultrasonically inspectable. The curvature of a 4-in.-long radius elbow is too great to facilitate ultrasonic angle beam scanning on the inside radius. However, most of the circumferential elbow weld is inspectable using this method.

A half-coupling for an ILRT test connection, located close to the weld on the HPCI steam supply piping, prevents this pipe-to-valve weld from being 100% volumetrically inspectable using ultrasonic inspection methods. Because of a blind area behind the half-coupling, only 95% of the weld is inspectable using an ultrasonic angle beam scanning technique.

The penetration assemblies are designed such that no circumferential pipe welds are enclosed. No inspection inside guard pipes are necessary.

Inspection intervals shall be in accordance with the requirements of ASME Code Section XI as described in the Inservice Inspection Program.

B. Pumps and Valves

Accessibility requirements include provision of sufficient space to disassemble and reassemble the pump or valve. For pumps or valves requiring only a visual examination, space for lighting and inspector access sufficient to permit observation of the entire valve inner surface was allowed. There are no through-wall casing welds in ASME Code-affected Class 1 pumps or valves.

C. Supports

The specific access requirements for supports depend on the type and detailed design of the support.

D. Reactor Vessel

The reactor vessel shield wall and insulation are designed to allow the reactor vessel longitudinal and circumferential shell welds, including the vessel-to-bottom head weld and bottom head welds, to be inspected from the outside diameter by a remotely operated scanning device. Primary nozzle-to-vessel welds, nozzle-to-vessel inside radiused section, and primary nozzle-to-safe end welds can also be examined by the use of the same type fixture.

The vessel-to-flange weld and the flange ligaments between the threaded stud holes are accessible during refueling.

Closure head-to-flange weld, closure head circumferential and meridional welds are accessible for inspection from the outside.

Reactor vessel closure studs, nuts, and washers can be removed to dry storage when the vessel head is removed. This will provide adequate access.

5.2.8.2.2 Class 2 Pressure-Retaining Components Access Provisions

The ASME Code, Section III, Class 2 pressure-retaining components subject to inspection are those components which comprise the ECCS and the main steam system from the outboard containment isolation valves to the main turbine stop valves and all branch lines larger than 4-in. nominal diameter to the first branch isolation valve.

The criteria followed to provide the accessibility for the performance of inspections per ASME Code, Section XI, for these components are:

A. Piping Welds

The accessibility for piping welds is based on providing the necessary unencumbered volume for ultrasonic inspection of the weld and base metal, as well as for visual and surface inspection of the weld and heat-affected zone on either side of the weld where ultrasonic examination will not be used.

For circumferential welds subject to surface and/or volumetric examination, the weld and base metal are accessible for 360 degrees about the pipe axis.

The following welds did not receive a full-code examination:

1. A weld between a tee and a weld-neck flange in the HPCI turbine steam line - The tee fitting and flange connect the auxiliary steam system to the HPCI turbine steam supply line for system testing of the HPCI turbine. Reconfiguration of the weld to accommodate inservice inspection would require redesign of the auxiliary steam system piping and removal and reinstallation of the weld-neck flange and a spool piece. In the case of the HPCI steam supply line, the result would be to replace one weld with two

welds, thus increasing the inservice inspection work load by yet another weld. In the case of the auxiliary steam system, the result would be the removal and replacement of many feet of 10-in. nominal diameter pipe to ensure correct condensate removal from the steam line.

This weld is evaluated in the high-energy line breaks report and has not been postulated as a break location because of its low calculated stresses. (Stress range is 30.3% of 0.8 ($S_h + S_A$), including earthquake.) Postulating failure at this weld would result in no more serious consequences than the weld discussed in item 2 below.

2. A weld between the outboard isolation valve and the tee discussed for the weld above - Reconfiguration of this weld would entail the addition of a spool piece between the valve and the tee, as well as the redesign of connected piping under the el 130-ft floor. The redesign of the connected piping would result in the fabrication of replacement pipe spools (ASME Code Section III, Class 2) for the installed piping, and would also result in core drilling the pipe penetration room floor to allow displacement of the HPCI steam line by the distance of the added spools. As in the case of the weld above, the addition of the spool piece will add an additional weld for inservice inspection.

   Although the physical rework is significant, the redesign would also require reanalysis of the piping system.

   Because this weld is classified as a "terminal end" under the high-energy line break criteria, failure of this weld was evaluated and is discussed in paragraph 15A.5.3.1.C.

3. Two RHR system mirror-image welds on the reduced pressure steam supply pipe are located between the pressure-reducing valve and the RHR heat exchanger on both RHR system heat exchangers. The welds connect a 6-in. nominal diameter supply pipe to a 16-in. nominal diameter, 180-degree return bend/expansion loop. Reconfiguration of the weld for inservice inspection would require the addition of two pipe reducer fittings, a spool piece between the reducer fittings, and modification of the already installed piping return bend.

   As in the case of the weld reconfiguration in the HPCI steam supply line, the redesign and modification of this piping would also require reanalysis of the piping system.

   The RHR system is classified for high-energy/moderate-energy line breaks criteria as a moderate-energy line. Cracks are postulated to occur in the moderate-energy fluid system lines wherever the calculated stresses exceed 0.4 ($1.2\ S_h + S_A$). A review of the stress analysis, including earthquake loadings, indicates that these welds have calculated stresses $< 0.4\ (1.2\ S_h + S_A)$.

B. Pumps and Valves

Accessibility requirements to permit inspection are, in most cases, less stringent than the space requirements for disassembly and maintenance of the equipment; therefore, maintenance accessibility was the overriding consideration during design.

For pumps and valves with pressure-retaining welds, access for volumetric examination of the weld and one thickness of base metal was provided where practical.

C. Supports

The access requirements for supports devices and components depend upon the specific of the support design, and sufficient space is provided for inspection activities where practical.

5.2.8.2.3 Equipment for Inservice Inspections

Reactor vessel insulation design provides an annulus between the vessel outside diameter and the inner surface of the insulation. This annulus was planned to extend from the lower portion of the support skirt to above the top of the sacrificial shield. The insulation design also includes design features at the nozzle to provide an annulus between the nozzle-to-safe-end weld and the inner surface of the insulation.

The equipment used for inservice inspection on HNP-2 is similar to that used on HNP-1. An ultrasonic device similar to the device used on other recent BWR vessels operates within the reactor vessel insulation annulus. This device is capable of virtually unlimited vertical travel from point of entry and out to a distance of 19 in. on either side of the traverse line. This allows inspection of virtually all of the vertical welds and ~ 70 ft of the circumferential weld. The reactor vessel bottom head design minimizes the welds to be inspected. An ultrasonic device has been developed capable of inspecting these welds by utilizing tracks and entry from four inspection ports in the reactor vessel support skirt.

A device is available to operate in the annulus provided around the nozzles.

5.2.8.2.4 Recording and Comparing Data

The results of manual inspections were recorded on forms designated for electronic data processing. This data can be transferred to a computer for correlation on subsequent inspections.

The results of mechanized scans were recorded by a data acquisition system. This system uses a stop-motion camera or video tape to record the information on a data panel. This panel contains meters and digital counters that indicate the position of the inspection device,

transducer angle, and scan path. Cathode ray tubes display the ultrasonic information from each instrument. A graphic presentation of the weld being inspected, showing idealized beam paths weld geometry, etc., can be recorded on video tape along with the cathode ray tube display. In addition, indications above a preset level are recorded on a strip chart recorder, with both time and amplitude being recorded.

5.2.8.2.5 Reactor Vessel Acceptance Standards

The acceptance standards that were used to establish the acceptability of the reactor vessel by ultrasonic examination are those of the 1974 ASME Code, Section XI, through the Summer 1975 Addenda. See paragraph 5.2.8.2 for current commitments.

5.2.8.2.6 Coordination of Inspection Equipment With Access Provisions

SNC has available the services of an experienced consulting firm for assistance in future inservice inspections, if required.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

REFERENCES

1. Williams, W. L., Corrosion, Volume 13, p 539t, 1957.

2. Skarpelos, J. M., and Bagg, J. W., "Chloride Control in BWR Coolants," NEDO-10899, June 1973.

3. Reynolds, M. B., "Failure Behavior in ASTM A 106 B Pipes Containing Axial Through-Wall Flaws," GEAP-5620, April 1968.

4. Duffy, A. R., Eiber, R. J., and Maxey, W. A., Recent Work on Flow Behavior in Pressure Vessels, April 1969; Eiber, et al., "Investigation of the Initiation and Extent of Ductile Pipe Rupture," Quarterly Progress Reports, May 1966 through 1969.

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

6. "Alternate Alloys for BWR Pipe Applications," EPRI, NP-2671-LD, Final Report, October 1982.

7. "Fracture Toughness Requirements", Appendix G to Title 10 Code of Federal Regulations Part 50, December 1995.

8. "Radiation Embrittlement of Reactor Vessel Materials", USNRC Regulatory Guide 1.99, Revision 2, May 1988.

9. Georgia Power Company letter to the Nuclear Regulatory Commission, dated June 30, 1988.

10. Georgia Power Company letter to the Nuclear Regulatory Commission, dated September 27, 1988.

11. Georgia Power Company letter to the Nuclear Regulatory Commission, dated October 19, 1988.

12. Nuclear Regulatory Commission letter to Georgia Power Company, dated February 16, 1990.

13. Georgia Power Company letter to the Nuclear Regulatory Commission, dated August 20, 1990.

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

15. H. S. Mehta, T. A. Caine, and S. E. Plaxton, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 through BWR/6 Vessels, NEDO-32205-A, Revision 1, General Electric Company, San Jose, CA, February 1994.

16. Frew, B. D., "Plant Hatch Unit 1 RPV Surveillance Materials Testing and Analysis", GE-NE-131100691-01R1, March 1997.

17. Paine, T. A. "E.I. Hatch Nuclear Power Station Unit 2 Vessel Surveillance Materials Testing and Fracture Toughness Analysis," SASR 90-104, May 1991.

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

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

20. "PVRC Recommendations on Toughness Requirements for Ferritic Materials," Welding Research Council Bulletin 175, August 1972.

21. ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, Nonmandatory Appendix G, "Fracture Toughness Criteria for Protection Against Failure," 1989 Edition, No Addenda.

22. "Design Stress Intensity Values, Allowable Stresses, Material Properties, and Design Fatigue Curves," ASME Boiler and Pressure Vessel Code, Section III, Appendix I, 1989.

23. "Plant Hatch Units 1 & 2 RPV Pressure Temperature Limits License Renewal Evaluation," General Electric Report GE-NE-B1100827-00-01, Class II, March 1999.

24. "Structural Integrity Report SIR-00-037, Revised Pressure-Temperature Curves for Plant Hatch," Revision 0, March 2000.

25. ASME Boiler and Pressure Vessel Code, Code Case N-588, "Attenuation to Reference Flow Orientation of Appendix G for Circumferential Welds in Reactor Vessels," Section XI, Division 1, approved December 12, 1997.

26. ASME Boiler and Pressure Vessel Code, Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves," Section XI, Division 1, approved February 26, 1999.

27. Paine, T. A. "Basis for GE RT_{NDT} Estimation Method," NEDC-32399-P, General Electric Company, November 1993.

28. C. Terry (BWRVIP) to U.S. NRC Document Control Desk, "Project No. 704-BWR Vessel and Internals Project, BWR Integrated Surveillance Program Plan (BWRVIP-78)," December 22, 1999.

29. C. Terry (BWRVIP) to U.S. NRC Document Control Desk, "Project No. 704-BWRVIP-86: BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan," EPRI Technical Report 1000888, December 22, 2000.

30. C. Terry (BWRVIP) to U.S. NRC Document Control Desk, "Project No. 704-BWRVIP Response to NRC Request for Additional Information Regarding BWRVIP-78," December 15, 2000.

31. C. Terry (BWRVIP) to U.S. NRC Document Control Desk, "Project No. 704-BWRVIP Response to Second NRC Request for Additional Information on the BWR Integrated Surveillance Program," May 30, 2001.

32. W. H. Bateman (USNRC) to C. Terry (BWRVIP), "Safety Evaluation Regarding EPRI Proprietary Reports," BWR Vessel and Internals Project, BWR Integrated Surveillance Program Plan (BWRVIP-78)" and "BWRVIP-86: BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan," February 1, 2002.

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

34. "10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2," GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

35. SNC-FLU-001-R-001 Revision 1, Edwin I. Hatch Unit 1 Reactor Pressure Vessel Fluence Evaluation at End of Cycle 21 and 49.3 EFPY, dated June 16, 2006.

36. SNC-FLU-002-R-001 Revision 0, Edwin I. Hatch Unit 2 Reactor Pressure Vessel Fluence Evaluation at End of Cycle 18 and 50.1 EFPY, dated April 23, 2007.

37. SNC-HA1-002-R-001 Revision 0, Edwin I. Hatch Unit 1 Fluence Evaluation at End of Cycle 25 and 49.3 EFPY, dated October 5, 2012.

38. SNC-HA2-001-R-001 Revision 0, Edwin I. Hatch Unit 2 Fluence Evaluation at End of Cycle 22 and 50.1 EFPY, dated April 16, 2014.

39. Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001.

40. BWRVIP Letter 2005-308, "NRC Safety Evaluation of RAMA Fluence Methodology," dated July 25, 2005.

TABLE 5.2-1 (SHEET 1 OF 3)

DESIGN TEMPERATURE AND PRESSURE AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[(a)] (psig)
RPV	575	1250	1563[(a)]
RRS			
Pump discharge piping	575	1450	(b)
Pump suction piping	575	1250	(b)
Discharge valves	575	1525	(c)
Suction valves	575	1250	(c)
Pump	575	1500	
RPV drain line	575	1275	(b)
Main steam line	575	1250	(b)
MSIVs	575	1250	(c)
RHR system			
Shutdown suction			
RRS header to second isolation valve			
Piping	575	1250	(b)
Valves	575	1250	(c)
Pump discharge			
RRS header to second isolation valve			
Piping	575	1450	(b)
Valves	575	1450	(c)
Reactor Feedwater System			
RPV to second isolation valve			
Piping	575	1300	1563
Valves	575	1300	1563

TABLE 5.2-1 (SHEET 2 OF 3)

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[a] (psig)
RCIC System			
Steam to RCIC turbine			
RPV to second isolation valve			
Piping	575	1250	(b)
Valves	575	1250	(c)
HPCI system			
Steam to HPCI turbine			
RPV to second isolation valve			
Piping	575	1250	1663
Valves	575	1250	1663
CS system			
Pump discharge			
RPV to first isolation valve			
Piping	575	1250	(b)
Valves	575	1250	(c)
First isolation valve to second isolation valve			
Piping	560	1124	(b)
Valves	560	1124	(c)
Standby Liquid Control System			
Pump discharge to RPV			
Reactor to second isolation valve			
Piping	575	1250	(b)
Valves	575	1250	(c)

TABLE 5.2-1 (SHEET 3 OF 3)

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[a] (psig)
RWC system			
Pump suction			
RHR piping to isolation valve outside drywell			
Piping	575	1250	(b)
Valves	575	1250	(c)
Control Rod Drive Hydraulic System			
Reactor to second isolation valve			
From RPV to F087	560	1250	1563
From F087 to F121	150	1750	2188

a. Excluding shell test for valves according to Sections NB-3531-8 and NB-3531-9 of ASME B&PV Code Section III. The stress intensity ratio is interpreted from Section NB-6221 of the code to be the ratio of the allowable stress, Sm, at test temperature to the allowable stress, Sm, at design temperature.
b. Test pressure is 1.25 x design pressure x lowest stress intensity ratio.
c. Test pressure is 1.50 x design pressure x lowest stress intensity ratio.

TABLE 5.2-3

REACTOR VESSEL MATERIAL IRRADIATION SURVEILLANCE SCHEDULE

ISP Capsule	Year to be Withdrawn or Tested																			
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Later
Browns Ferry 2		X	------------------------->>									**X**								
Cooper																	**X**			
Dresden 3			X	------------------------->>													**X**			
Duane Arnold														**X**						
Hatch 1																		**X**		
Hatch 2		X	------------------------->>															**X**		
Hope Creek					X	------------------------->>									**X**					
LaSalle 1						X	------------------------->>				**X**									
Monticello				X	----------->>		**X**													
Peach Bottom 2			X	------------------------->>															**X**	
Perry								X	------------------------->>				**X**							**X (2026)**
River Bend			**X**		X	------------------------->>														**X (2025)**
Susquehanna 1			X	------------------------->>								**X**								
SSP-A				**X**																
SSP-B				**X**																
SSP-C				**X**																
SSP-D	**X**																			
SSP-E		**X**																		
SSP-F		**X**																		
SSP-G	**X**																			
SSP-H	**X**																			
SSP-I		**X**																		

Notes:

1. Bold X indicates the schedule under the ISP; arrows indicate shifts from the existing schedule.
2. Browns Ferry 2 was scheduled to withdraw its second capsule in 2001; to increase fluence per NRC Staff recommendations, the ISP delays withdrawal until 2011.
3. Dresden 3, Hatch 2, Hope Creek, LaSalle 1, Monticello, Peach Bottom 2, and Susquehanna 1 final capsule withdrawals are deferred to increase capsule fluence.
4. River Bend withdrew a capsule in 2000 and will test and report the results in 2003.
5. River Bend was scheduled to withdraw its second capsule in 2004, soon after withdrawing its first; to increase fluence per NRC Staff recommendations, the ISP delays withdrawal until 2025.
6. Cooper, Duane Arnold, and Hatch 1 are scheduled for third capsule withdrawals as shown, based on NRC Staff recommendations.
7. Year for capsule withdrawal is approximate; to be coordinated with plant outage schedule.

TABLE 5.2-4

NUCLEAR STEAM SUPPLY SYSTEM SAFETY RELIEF VALVES AND ELECTRICAL BACKUP: SET PRESSURES, CAPACITIES, AND DURATION OF BLOWDOWN

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

Events Resulting in Pressure Relief Actuation	No. of Valves Expected to Operate During First Blowdown	Duration of First Blowdown(s)
Generator load rejection	10 of 11	5
Turbine trip (nominal)	10 of 11	5
Turbine trip without bypass	10 of 11	5
Turbine trip without bypass - low power	< 11	-
Closure of all MSIVs	10 of 11	> 8
Pressure regulator failure - fail open	4	2
Loss of auxiliary power	8	3
Feedwater controller failure - maximum flow	0	-
Inadvertent opening of a safety relief valve	1	-

a. The number of safety relief valves required to actuate to provide automatic depressurization is six of seven. This provides sufficient flow capacity to satisfy automatic depressurization requirements, assuming one ADS valve fails to open.
b. This column reflects the nominal safety relief valve set pressure for nonsafety electrical backup to mechanical relief valves.

TABLE 5.2-5

KEY ANALYSIS INPUT PARAMETERS AND ASSUMPTIONS FOR EXTENDED POWER UPRATE OVERPRESSURE PROTECTION ANALYSIS

Parameter	Value
Rated thermal power (MWt)	2763
Analysis power (MWt) (102% of rated)	2818
Core flow (% of rated)	105
Dome pressure (psia)	1073
Rated feedwater temperature (°F)	425
No. of safety relief valves (SRVs)	10 of 11
SRV type	Target Rock
SRV opening response time (s)	0.15
SRV opening delay time (s)	0.4
Total SRV capacity (% rated steam flow)[a] at 1090 psig	71
Scram speed	GEMINI Option A

The impact of thermal power optimization (2804 MWt) and reactor operating pressure increase to 1060 psia has been evaluated with a peak calculated RPV bottom head pressure increase to 1349 psig, which is well within the event acceptance limit of 1375 psig.

a. The absolute SRV capacity at 1090 psig does not change with power uprate. The reduction in the capacity relative to the rated steam flow at 2763 MWt is due to the increase in the rated value with power uprate.

TABLE 5.2-6 (SHEET 1 OF 2)

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
RPV heads, shells	Rolled plate or forgings	Low-alloy steel	SA-533 Grade B or SA-508 Cl 2
	Welds	Low-alloy steel	SFA-5.5
Closure flange	Forged ring welds	Low-alloy steel Low-alloy steel	SA-508 Cl 2 SFA-5.5
Nozzles	Forged shapes welds	Low-alloy steel Low-alloy steel	SA-508 Cl 2 SFA-5.5
Cladding	Weld overlay	Austenitic stainless steel	SFA-5.9 or SFA-5.4 TP 309 with carbon content of final surface limited to 0.08% maximum
CRD stub tubes	Forged or extruded	Inconel-clad low-alloy steel or clad carbon steel	SB166, SB16T or SA-508
	Welds	Inconel or stainless steel	SFA-5.14 TP ERNiCr-3, SFA-5.11 TP ERNiFE-3 or SFA-5.9, SFA-5.4 TP, 308L or 316L
Control rod	Pipe	Austenitic stainless steel	SA-312
Drive housings	Welds	Stainless steel	SFA-5.9 TP308 or 316, or SFA-5.2 TP308 or 316L
Incore	Pipe	Austenitic stainless steel	SA-213
Housings	Welds	Stainless steel	SFA-5.9 or 5.4 TP 308 or 316

Additional RCPB component materials and specifications to be used are specified as follows.

Depending on whether impact tests are required and depending on the lowest service metal temperature when impact tests are required, the following ferritic materials and specifications are to be used:

TABLE 5.2-6 (SHEET 2 OF 2)

Pipe	SA-106 Grade B, SA-333 Grade 6, and SA-155 Grade KCF-70
Valves	SA-105 Grade II, SA-350 Grade LF1, and SA-216 Grade WCB
Fittings	SA-105 Grade II, SA-350 Grade LF1, SA-234 Grade WPB, and SA-420 Grade WPL1 or WPL6
Bolting	SA-193 Grade B7, SA-194 Grades 7 and 2H, and SA-540 Grade B22, B23, and B24
Welding material	SFA-5.1 (E-7015, E-7016, E-7018) SFA-5 5(E-7010A1, E-7015, E-7016, E-7018) SFA-5.17, SFA-5.18

The replaced HNP-2 recirculation piping system, stainless steel portions of RHR, and replaced portion of RWC are fabricated of materials according to the following specifications:

Pipe	SA-358 Type 316NG, Class 1
Fittings	SA-403 Grade WP316NG
Forgings	SA-182 Grade F316NG
Weld filler metal	
Seam welds	SFA 5.9 Type ER316L
Butt welds and attachment welds	SFA 5.4 Type E308L SFA 5.9 Type ER308L

For the recirculation system pumps and valves and other systems or portions of systems requiring austenitic stainless steel, the following materials and specifications are to be used:

Pipe	SA-376 Type 304, SA-312 Type 304, SA-358 Type 304
Valves	SA-182 Grade F-304, SA-351 Grades CR-8 and CR-8M
Pump	SA-182 Grade F-304, SA-351 Grades CF-8 and CR-8M
Flanges	SA-182 Grade F-316
Bolting	SA-193 Grade B7, SA-194 Grades 7 and 2H, SA-540 Grades B22, B23, B24
Welding material	SFA-5.4 (E308-15, E308L-15, E316-15), SFA-5.9 (ER-308, ER-308L, ER-316)

TABLE 5.2-7 (SHEET 1 OF 2)

BELTLINE ART VALUES

HNP-1

Thickness (in.) = 5.38	**Lower Intermediate** Ratio Peak/Location	= 1.00	54 EFPY Peak I.D. fluence	=	3.5E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	2.5E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	2.5E+18	n/cm^2
Girth Weld Thickness (in.) = 5.38	**Lower** Ratio Peak/Location	= 0.68	54 EFPY Peak I.D. fluence	=	2.4E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	1.7E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	1.7E+18	n/cm^2
Plate & Longitudinal Weld Thickness (in.) = 6.38	Ratio Peak/Location	= 0.68	54 EFPY Peak I.D. fluence	=	2.4E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	1.6E+18	n/cm^2
			54 EFPY Peak 1/4 T fluence	=	1.6E+18	n/cm^2

Component	Heat or Heat/Lot	%/Cu	%Ni	CF	Initial RT_{ndt} (°F)	¼ T Fluence n/cm^2	54 EFPY ΔRT_{ndt} (°F)	σ_1	$\sigma\Delta$	Margin (°F)	54 EFPY Shift (°F)	54 EFPY ART (°F)
PLATES:												
Lower												
G-4805-1	C4112-1	0.13	0.64	92	8	1.6E+18	48	0	17	34	81.9	89.9
G-4805-2	C4112-2	0.13	0.64	92	10	1.6E+18	48	0	17	34	81.9	91.9
G-4805-3	C4149-1	0.14	0.57	99	-10	1.6E+18	52	0	17	34	85.5	75.5
Lower-Intermediate												
G-4803-7	C4337-1	0.17	0.62	128	-20	2.5E+18	80	0	17	34	114.3	94.3
G-4804-1	C3985-2	0.13	0.58	90	-20	2.5E+18	56	0	17	34	90.5	70.5
G-4804-2*	C4114-2	0.13	0.70	245	-20	2.5E+18	154	0	17	34	187.7	167.7
WELDS:												
Lower Longitudinal 1-307	13253/1092 Flux 3791	0.221	0.732	189	-50	1.6E+18	98	0	28	56	154.4	104.4
Lower Intermediate Longitudinal 1-308	IP2809/1092 Flux 3854	0.270	0.735	206	-50	2.5E+18	129	0	28	56	185.0	135.0
1-308	IP2815/1092 Flux 3854	0.316	0.724	219	-50	2.5E+18	137	0	28	56	193.4	143.4
Girth (Lower to Lower-Intermediate) 1-313	90099/0091 Flux 3977	0.197	0.060	91	-10	1.7E+18	49	0	24	48	97.3	87.3
1-313	33A277/0091 Flux 3977	0.258	0.165	126	-50	1.7E+18	67	0	28	56	123.3	73.3

*CF adjusted by a factor of 2.62.

TABLE 5.2-7 (SHEET 2 OF 2)

BELTLINE ART VALUES

HNP-2

	Lower Intermediate				
Thickness (in.) = 5.38	Ratio Peak/Location	=	1.00	54 EFPY Peak I.D. fluence = 3.9E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 2.8E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 2.8E+18	n/cm^2
	Lower				
Girth Weld Thickness (in.) = 5.38	Ratio Peak/Location	=	0.64	54 EFPY Peak I.D. fluence = 2.5E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 1.8E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 1.8E+18	n/cm^2
Plate & Longitudinal Weld Thickness (in.) = 6.38	Ratio Peak/Location	=	0.64	54 EFPY Peak I.D. fluence = 2.5E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 1.7E+18	n/cm^2
				54 EFPY Peak 1/4 T fluence = 1.7E+18	n/cm^2

Component	Heat or Heat/Lot	%Cu	%Ni	CF	Initial RT_{ndt} (°F)	¼ T Fluence n/cm^2	54 EFPY ΔRT_{ndt} (°F)	σ_1	σ_Δ	Margin (°F)	54 EFPY Shift (°F)	54 EFPY ART (°F)
PLATES:												
Lower	C8553-2	0.08	0.58	51	-20	1.7E+18	27	0	13	27	54.0	34.0
G6603-1	C8553-1	0.08	0.58	51	24	1.7E+18	27	0	13	27	54.0	78.0
G6603-2	C8571-1	0.08	0.53	51	0	1.7E+18	27	0	13	27	54.0	54.0
G6603-3												
Lower-Intermediate	C8554-1	0.08	0.57	51	-20	2.8E+18	33	0	17	33	66.5	46.5
G6602-2	C8554-2	0.08	0.63	51	-10	2.8E+18	33	0	17	33	66.5	56.5
G6602-1	C8579-2	0.11	0.48	73	-4	2.8E+18	48	0	17	34	81.6	77.6
G6601-4												
WELDS:												
Lower Longitudinal 101-842	10137, Linde 0091	0.216	0.043	98	-50	1.7E+18	52	0	26	52	103.7	53.7
Lower-Intermediate Longitudinal 101-834	51874, Linde 0091, Flux 3458	0.147	0.037	68	-50	2.8E+18	44	0	22	44	88.7	38.7
Girth (Lower to Lower- Intermediate) 301-871	4P6052, Linde 0091, Flux 0145	0.047	0.049	31	-50	1.8E+18	17	0	8	17	33.7	-16.3

TABLE 5.2-8

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

Function		A	A	A	A	A/I	A	A/I	A/I	A	A/I	A/I	I	I	A/I
Source of Leakage	Location	PC High Temperature	PC Sump High Flowrate	PC Air Cooler CW ΔT (High)	Equipment Area T & ΔT (High)	Low Steam Line Pressure	RB Sump High Flowrate	Equipment Area T (High	Suppresion Pool Area T and ΔT (high) Time Relay	PC Pressure (High)	High Flowrate	High Turbine Exhaust Pressure	CU Δ Flow (High)	Reactor Low Water Level 1, 2, or 3	Reactor Pressure
Main steam line	PC	X	X	X						X				X	
	RB				X[a]		X				X[b]			X	
	TB				X[a]										
RHR	PC	X	X	X						X				X[d]	X[d]
	RB				X		X								
RCIC or HPCI steam	PC	X	X	X						X					
	RB					X	X	X	X		X[b]		X		
RCIC or HPCI water	PC														
	RB						X								
Cleanup water	PC	X	X	X						X			X		
	RB	Hot			X[c]		X						X	X	
	RB	Cold					X						X	X	
										x					
Feedwater	PC	X	X	X											
	RB						X								

LEGEND:

A - Alarm
I - Isolation
PC - Primary containment
RB - Reactor building
CU - Reactor water cleanup
CW - Reactor building chilled water
TB - Turbine building

a. Isolate on high ambient temperature in main steam tunnel or pipe chase.
b. Break downstream of flow element will isolate the steam line.
c. Isolates on high temperature or high differential temperature in the RWC equipment room.
d. Isolates shutdown cooling suction path of RHR only.

TABLE 5.2-9 (SHEET 1 OF 2)

RT_{NDT} VALUES FOR REACTOR VESSEL MATERIALS
(HNP-1)

Component	ID	Heat	Test Temp (°F)	Charpy Energy (ft-lb)			(T_{sot}-60) (°F)	Drop Weight NDT	RT_{NDT} (°F)
Plates & Forgings									
Top Head & Plate									
Dollar Plate	G-4412	C4845-3	10	48	52	53	-16	-10	-10
Top Head Torus	G-4811	C4180-2	10	74	83	67	-20	-10	-10
Top Head Flange	G-4802	AHY-120	10	141	148	188	-20	10	10
Shell Courses									
Upper Shell	G-4803-2	C4134-2	10	50	53	52	-20	-10	-10
	G-4803-3	C4121-2	10	45	32	40	16	-10	16
	G-4803-5	C4116-2	10	41	49	47	-2	-10	-2
Flange	G-4801	AFZ-148	10	86	67	70	-20	10	10
Upper Intermediate Shell	G-4803-1	C4114-1	10	26	23	30	34	-10	34
	G-4803-4	C4116-1	10	23	24	24	34	-10	34
	G-4803-6	C4121-1	10	32	35	23	34	-10	34
Lower Intermediate Shell	G-4803-7	C4337-1	10	74	78	53	-20	-40	-20
	G-4804-1	C3985-2	10	65	82	71	-20	-20	-20
	G-4804-2	C4114-2	10	84	80	82	-20	-40	-20
Lower Shell	G-4805-1	C4112-1	10	42	40	36	8	-10	8
	G-4805-2	C4112-2	10	38	50	35	10	-10	10
	G-4805-3	C4149-1	10	49	67	58	-18	-10	-10
Bottom Head Dollar Plate	G-4810	C4351-3	10	70	68	60	-20	10	10
Bottom Head Torus	G-4807	C4100-2	10	71	65	76	-20	-10	-10
	G-4808	C4100-1	10	80	86	91	-20	-10	-10
	G-4809	C4182-3	10	85	82	92	-20	-10	-10

TABLE 5.2-9 (SHEET 2 OF 2)
(HNP-1)

Component	ID	Heat	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{sot}$-60) (°F)	Drop Weight NDT	RT_{NDT} (°F)
Nozzles									
Recirc Outlet Nozzle	G-4819-1	AV-2798	10	35	51	42	10	0	10
	G-4819-2	AV-2797	10	38	43	49	4	0	4
Recirc Inlet Nozzle	G-4817-1-4	EV-9754	10	118	120	75	-20	-20	-20
	G-4817-5, 6	AV-1973	10	42	37	25	30	0	30
	G-4817-7-10	EV-9753	10	84	68	72	-20	-10	-10
Steam Outlet Nozzle	G-4818-1, 2	AV-2805	10	103	74	83	-20	10	10
	G-4818-3	AV-2840	10	78	102	76	-20	10	10
	G-3443-1	AV-1576	10	42	44	64	-4	40	40
Feedwater Nozzle	G-4816-1-4	AV-2796	10	66	40	57	0	10	10
Core Spray Nozzle	G-4815-1, 2	AV-2796	10	66	40	57	0	10	10
Top Head Instrumentation	G-2921-5, 6	EV-9781	10	82	69	72	-20	0	0
Vent Nozzle	G-2920	AV-2374	10	145	182	185	-20	0	0
Jet Pump Instrumentation	G-4813-1, 2	AV-2374	10	145	182	185	-20	-40	-20
CRD Hydraulic System Return	G-4814	AV-1909	10	84	117	78	-20	10	10
Drain Nozzle	G-4004	AV-1901	10	112	90	98	-20	NA	-20
Welds									
Vertical Welds	1-307	13253							-50
	1-308	1P2809							-50
		1P2815							-50
Girth Welds	1-313	90099							-10
		33A277							-50
Studs							LST		
	G-4851	38094	10	55	50	54	10	OK	
		37965	10	44	46	42	70	OK	
		13921	10	50	54	55	10	OK	

TABLE 5.2-10 (SHEET 1 OF 2)

LIMITING RPV MATERIAL ART_{NDT}

HNP-1

Part Name and Material	Heat No.	Initial RT_{NDT} (°F)	Chemistry %/Cu	Chemistry %Ni	CF	EFPY	Adjustments for 1/4T: ΔRT_{NDT} (°F)	Margin Terms: σΔ (°F)	Margin Terms: σ_1 (°F)	ART_{NDT} (°F)
Beltline Lower Intermediate	C4114-2	-20	0.130	0.700	245	20.0	96.7	17.0	0.0	110.7
						24.0	105.8	17.0	0.0	119.6
						28.0	113.4	17.0	0.0	127.4
						32.0	120.0(3)	17.0	0.0	133.9(3)
						36.0	127.0	17.0	0.0	141.0
						40.0	133.5	17.0	0.0	147.5
						44.0	139.7	17.0	0.0	153.7
						48.0	145.4	17.0	0.0	159.4
						54.0	154.0(3)	17.0	0.0	167.7(3)

Location	Wall thickness (in.) Full	Wall thickness (in.) 1/4T	EFPY	Fluence at ID (n/cm^2)	Attenuation at 1/4T $e^{-0.24nt}$	Fluence at 1/4T (n/cm^2)	Fluence Factor, FF $f^{(0.28 - 0.10 \log f)}$	Comments
Beltline Lower Intermediate	5.380	1.345	20.0	1.23E+18	0.724	8.93E+17	0.395	Fluence was linearly interpolated based on 36 EFPYs.
			24.0	1.48E+18	0.724	1.07E+18	0.431	Fluence was linearly interpolated based on 36 EFPYs.
			28.0	1.73E+18	0.724	1.25E+18	0.463	Fluence was linearly interpolated based on 36 EFPYs.
			32.0	2.00E+18(3)	0.724	1.40E+18(3)	0.492	Fluence was linearly interpolated based on 36 EFPYs.
			36.0	2.22E+18	0.724	1.61E+18	0.518	Fluence assumed such that resulting ART matched that given in ref 23.
			40.0	2.49E+18	0.724	1.80E+18	0.545	Fluence assumed such that resulting ART matched that given in ref 23.
			44.0	2.77E+18	0.724	2.01E+18	0.570	Fluence assumed such that resulting ART matched that given in ref 23.
			48.0	3.05E+18	0.724	2.21E+18	0.593	Fluence assumed such that resulting ART matched that given in ref 23.
			54.0	3.50E+18(3)	0.724	2.50E+18(3)	0.625	Fluence for this EFPY was given in ref 23.

TABLE 5.2-10 (SHEET 2 OF 2)

HNP-2

Part Name and Material	Heat No.	Initial RT_{NDT} (°F)	Chemistry %/Cu	Chemistry %Ni	CF	EFPY	ΔRT_{NDT} (°F)	Adjustments for 1/4T Margin Terms $\sigma\Delta$ (°F)	Adjustments for 1/4T Margin Terms σ_1 (°F)	ART_{NDT} (°F)
Beltline Lower	C8553-1	24	0.08	0.58	51	20.0	16.7	13.4	0.0	67.5
						24.0	18.4	13.4	0.0	69.2
						28.0	19.8	13.4	0.0	70.6
						32.0	21.0(3)	10.0(3)	0.0	65.5(3)
						36.0	22.4	13.4	0.0	73.2
						40.0	23.5	13.4	0.0	74.3
						44.0	24.6	13.4	0.0	75.4
						48.0	25.5	13.4	0.0	76.3
						54.0	27.0(3)	13.0(3)	0.0	78.0(3)

Location	Wall thickness (in.) Full	Wall thickness (in.) 1/4T	EFPY	Fluence at ID (n/cm^2)	Attenuation at 1/4T $e^{-0.24nt}$	Fluence at 1/4T (n/cm^2)	Fluence Factor, FF $f^{(0.28 - 0.10 \log f)}$	Comments
Beltline Lower	5.380 (See Note 2.)	1.345	20.0	8.56E+17	0.724	6.20E+17	0.328	Fluence was linearly interpolated based on 54 EFPYs.
			24.0	1.03E+18	0.724	7.43E+17	0.360	Fluence was linearly interpolated based on 54 EFPYs.
			28.0	1.20E+18	0.724	8.67E+17	0.389	Fluence was linearly interpolated based on 54 EFPYs.
			32.0	2.20E+18(3)	0.724	1.60E+18(3)	0.415	Fluence was linearly interpolated based on 54 EFPYs.
			36.0	1.54E+18	0.724	1.12E+18	0.439	Fluence was linearly interpolated based on 54 EFPYs.
			40.0	1.71E+18	0.724	1.24E+18	0.461	Fluence was linearly interpolated based on 54 EFPYs.
			44.0	1.88E+18	0.724	1.36E+18	0.482	Fluence was linearly interpolated based on 54 EFPYs.
			48.0	2.05E+18	0.724	1.49E+18	0.501	Fluence was linearly interpolated based on 54 EFPYs.
			54.0	3.90E+18(3)	0.724	2.80E+18(3)	0.528	See Note 3.

Notes:

1. HNP-1 data obtained from table 3.1 of reference 23. HNP-2 data obtained from table 3.2 of reference 23.
2. Reference 23 report developed a bounding P-T curve by using the smaller weld thickness, combined with the thicker lower plate material properties. For this analysis, the smaller thickness is shown (since the P-T curves are based on this thickness), but the ID fluence was adjusted to yield a 1/4T fluence that matched the value in table 3-2[23] for the limiting thicker plate. Therefore, the ID fluence value for 54 EFPYs was iterated until the appropriate calculated value at 1/4T was obtained. In effect, the values shown in this table reconcile the analysis case with the bounding case documented in reference 23.
3. Values updated based on RPV fracture toughness evaluation for TPO (GE-NE-0000-8119-01, Rev. 0, August 2002). The reactor operating pressure increase (ROPI) to 1060 psia had no impact on these values.

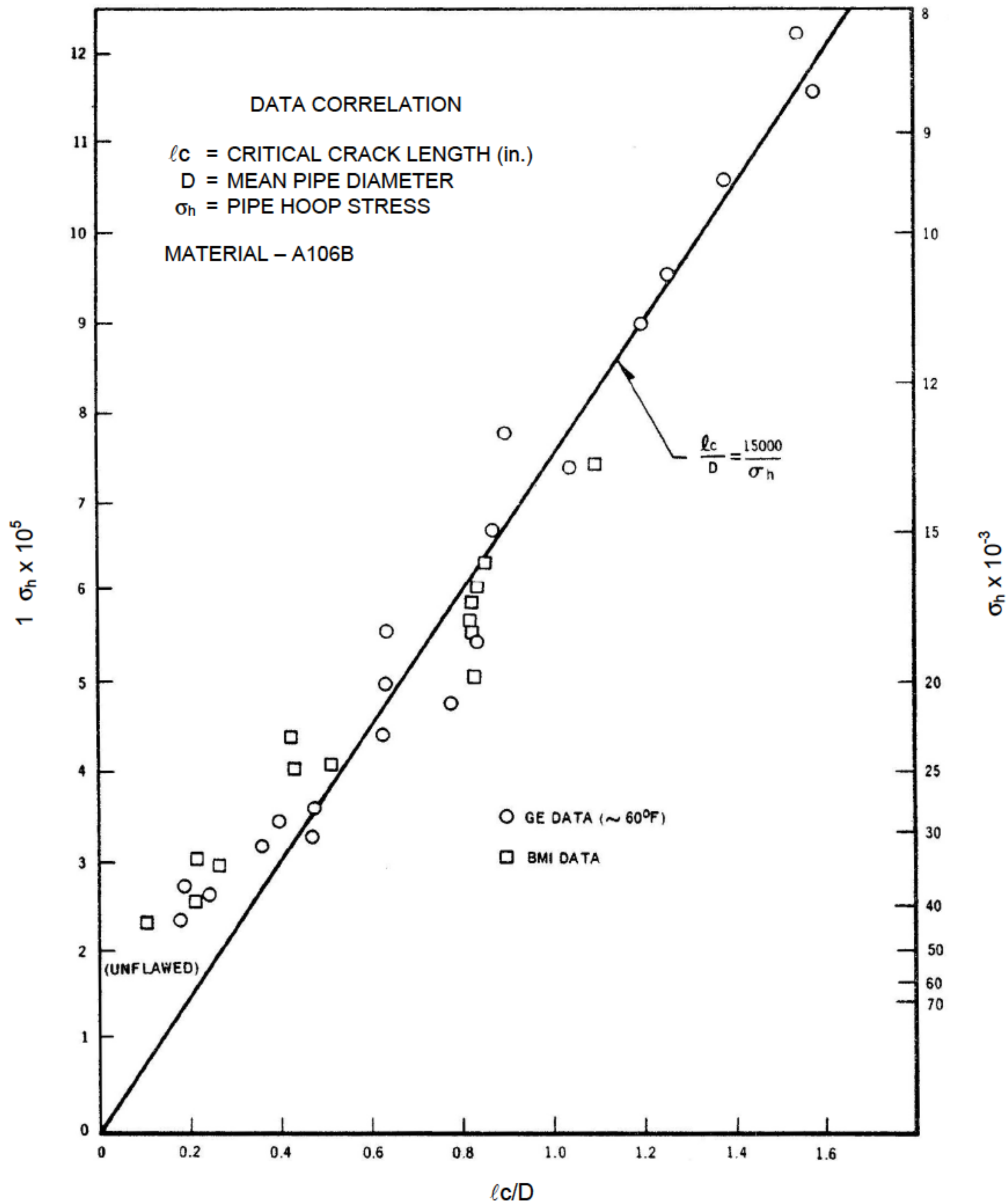
TABLE 5.2-11

ISP TEST MATRIX

		TARGET VESSEL WELDS AND PLATES																																																																		
		Browns Ferry 2 weld	Browns Ferry 2 plate	Browns Ferry 3 weld	Browns Ferry 3 plate	Brunswick 1 weld	Brunswick 1 plate	Brunswick 2 weld	Brunswick 2 plate	Clinton weld	Clinton plate	Cooper weld	Cooper plate	Dresden 2 weld	Dresden 2 plate	Dresden 3 weld	Dresden 3 plate	Duane Arnold weld	Duane Arnold plate	Enrico Fermi 2 weld	Enrico Fermi 2 plate	FitzPatrick weld	FitzPatrick plate	Grand Gulf weld	Grand Gulf plate	Hatch 1 weld	Hatch 1 plate	Hatch 2 weld	Hatch 2 plate	Hope Creek weld	Hope Creek plate	LaSalle 1 weld	LaSalle 1 plate	LaSalle 2 weld	LaSalle 2 plate	Limerick 1 weld	Limerick 1 plate	Limerick 2 weld	Limerick 2 plate	Monticello weld	Monticello plate	Nine Mile Point 1 weld	Nine Mile Point 1 plate	Nine Mile Point 2 weld	Nine Mile Point 2 plate	Oyster Creek weld	Oyster Creek plate	Peach Bottom 2 weld	Peach Bottom 2 plate	Peach Bottom 3 weld	Peach Bottom 3 plate	Perry weld	Perry plate	Pilgrim weld	Pilgrim plate	Quad Cities 1 weld	Quad Cities 1 plate	Quad Cities 2 weld	Quad Cities 2 plate	River Bend weld	River Bend plate	Susquehanna 1 weld	Susquehanna 1 plate	Susquehanna 2 weld	Susquehanna 2 plate	Vermont Yankee weld	Vermont Yankee plate	WNP-2 weld	WNP-2 plate
	Browns Ferry 2	1	1	1	1																																																															
	Browns Ferry 3																																																																				
	Brunswick 1																																																																				
	Brunswick 2																																																																				
	Clinton																																																																				
	Cooper											1	1													1																					1																						
	Dresden 2																																																																				
S	Dresden 3													1		1																																								1		1											
U	Duane Arnold						1		1									1	1																				1												1														1				1
R	Enrico Fermi 2																																																																				
V	FitzPatrick																																																																				
E	Grand Gulf																																																																				
I	Hatch 1																				1						1																																										
L	Hatch 2																											1	1													1				1																							
L	Hope Creek																													1	1																																						
A	LaSalle 1																						1									1	1																						1														
N	LaSalle 2																																																																				
C	Limerick 1																																																																				
E	Limerick 2																																																																				
	Monticello																																								1																												
C	Nine Mile Point 1																																																																				
A	Nine Mile Point 2																																																																				
P	Oyster Creek																																																																				
S	Peach Bottom 2																																				1								1			1	1																				
U	Peach Bottom 3																																																																				
L	Perry																							1	1																			1								1	1																
E	Pilgrim																																																																				
S	Quad Cities 1																																																																				
	Quad Cities 2																																																																				
	River Bend					2		2		1	1																								1	1		1		1										1										1	1			2				1	
	Susquehanna 1																																	1																												1	1			1	1		
	Susquehanna 2																																																																				
	Vermont Yankee																																																																				
	WNP-2																																																																				
	SSP					1	2	1	2	2		2			1		1	2	2	1		1		2	2	2										2		2	2	2			1	2						2	2	2	2	1			1		1	2				1	2			2	2

1 Selected to be in final ISP test matrix

2 Capsule(s) which contain the same heat as the Representative Material and whose results will also be considered

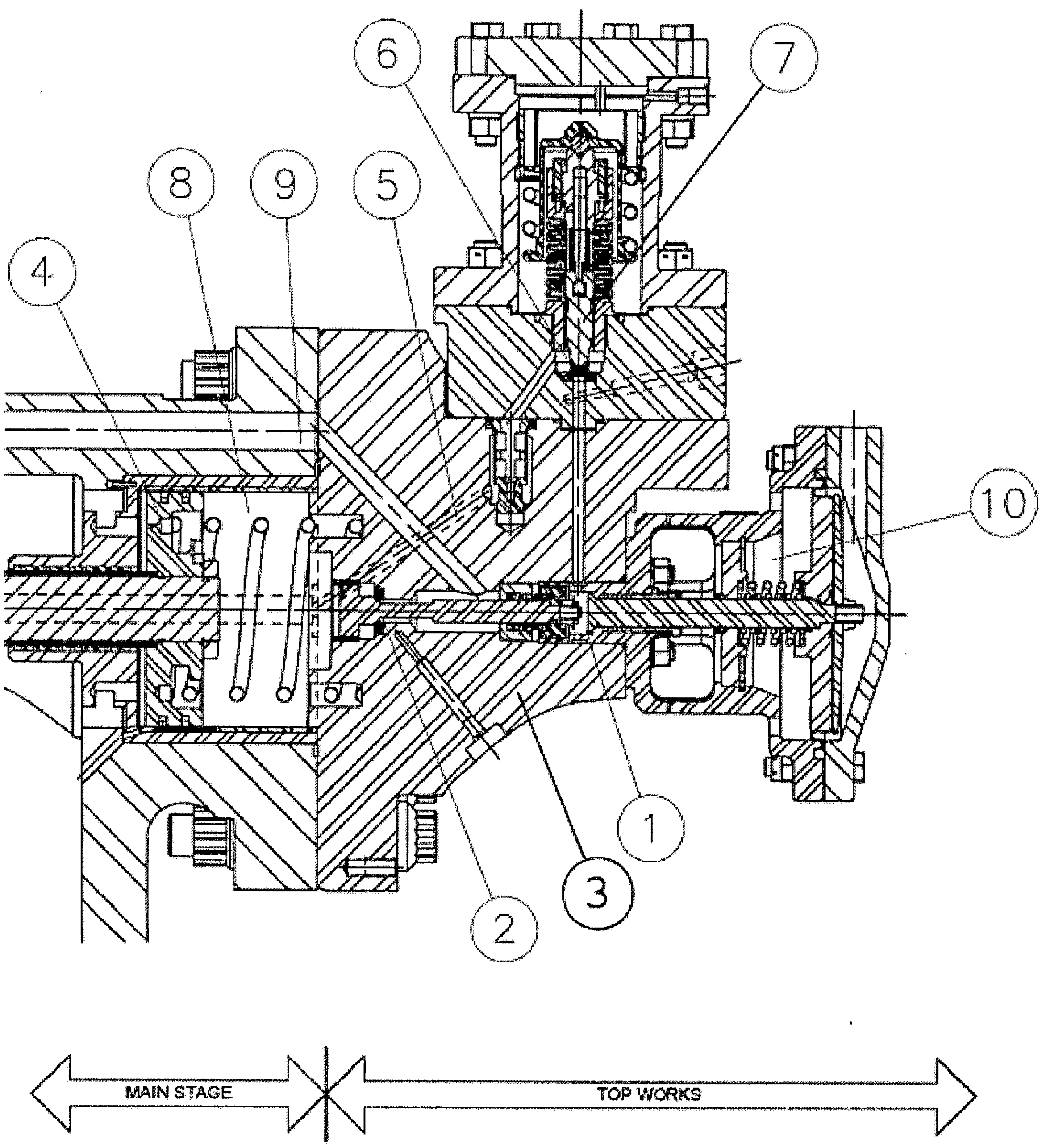


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

AXIAL THROUGH-WALL CRACK

FIGURE 5.2-1



REV 34 8/16

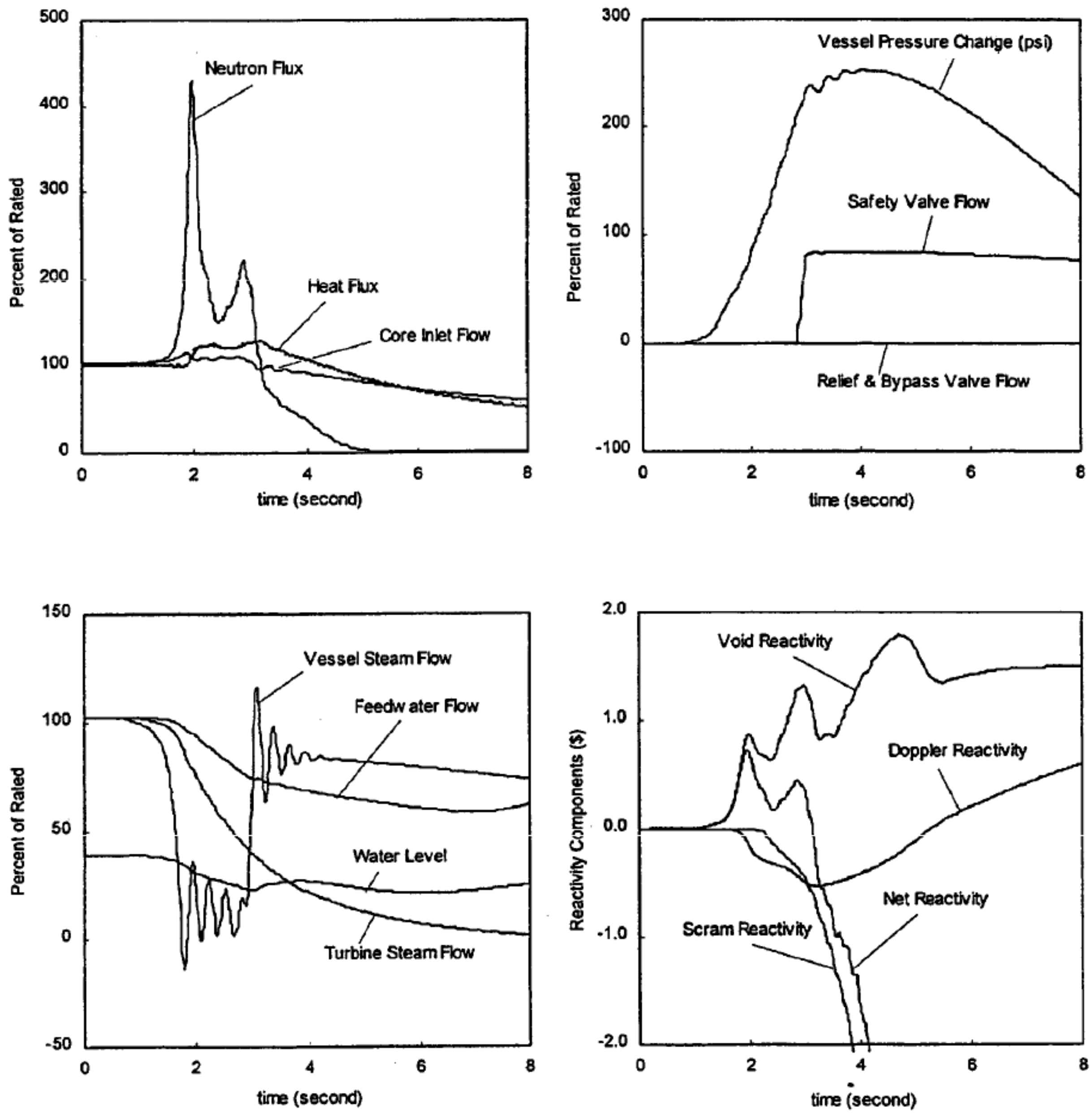
SOUTHERN COMPANY
Energy to Serve Your World

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

THREE-STAGE SAFETY RELIEF VALVES

FIGURE 5.2-2

(102% extended uprate power; 105% rated core flow; 1073 psia initial dome pressure)



ACAD 2050234

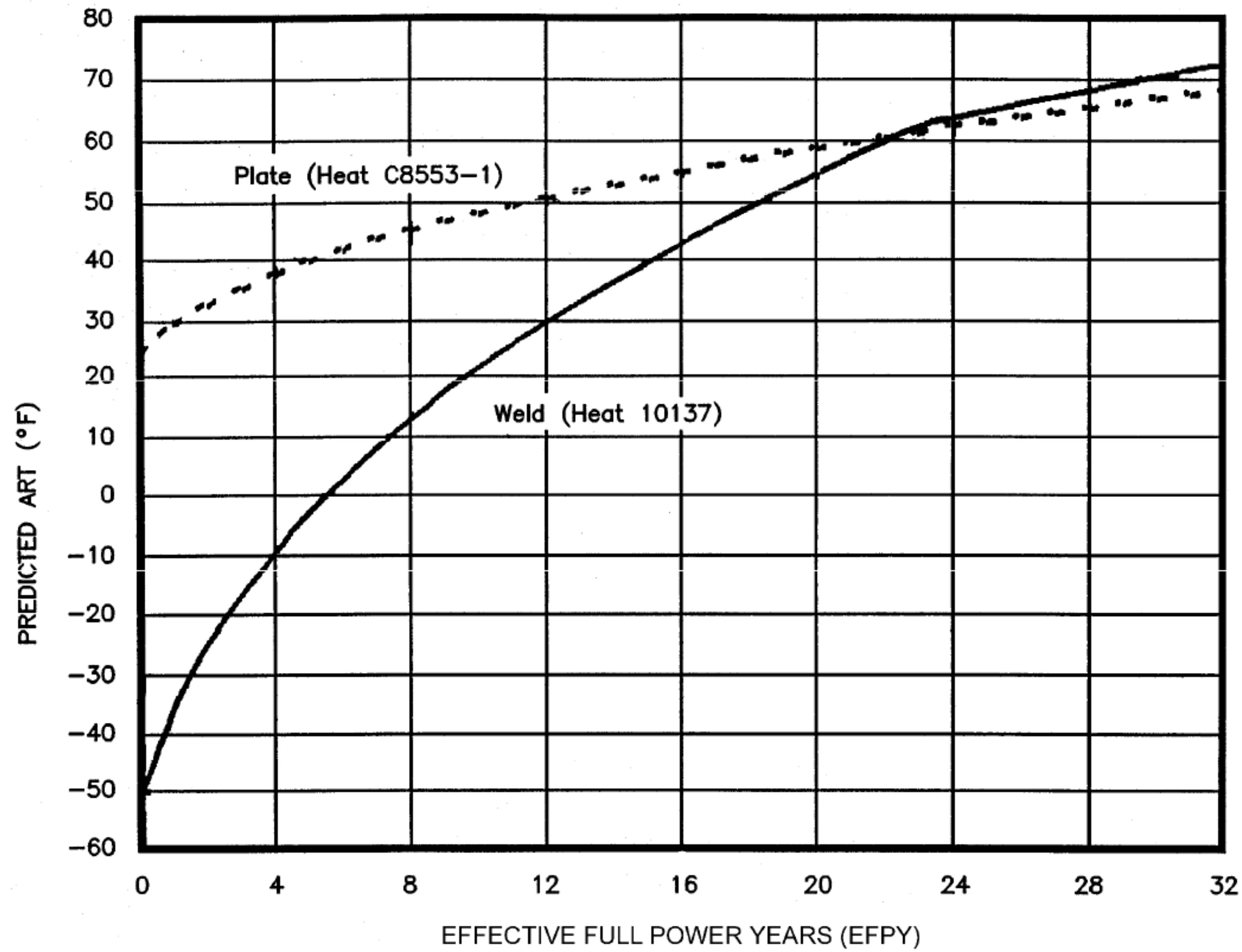
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RESPONSE TO MSIV
CLOSURE WITH FLUX SCRAM

FIGURE 5.2-3



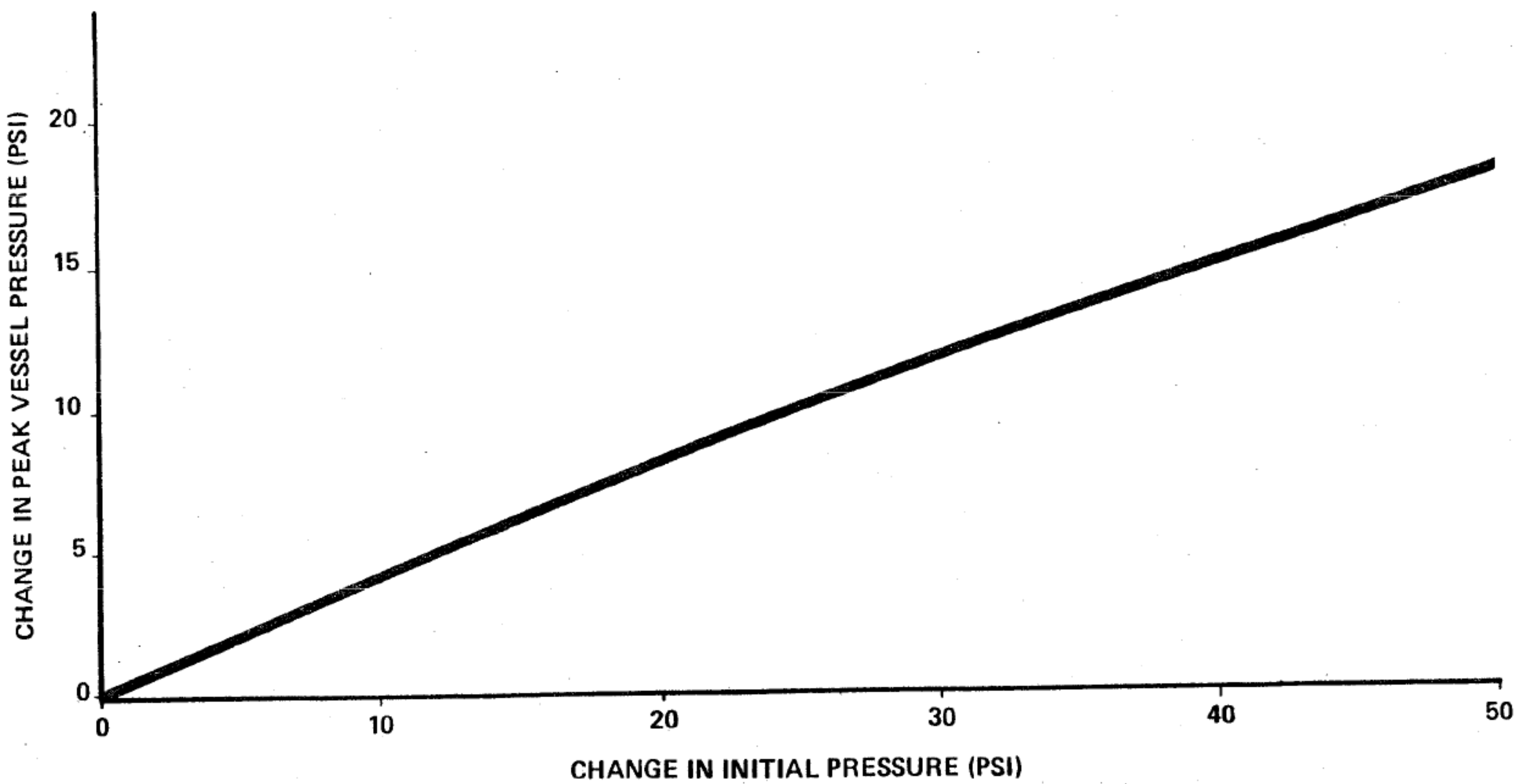
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ADJUSTED REFERENCE TEMPERATURE FOR LIMITED BELTLINE MATERIALS

FIGURE 5.2-4



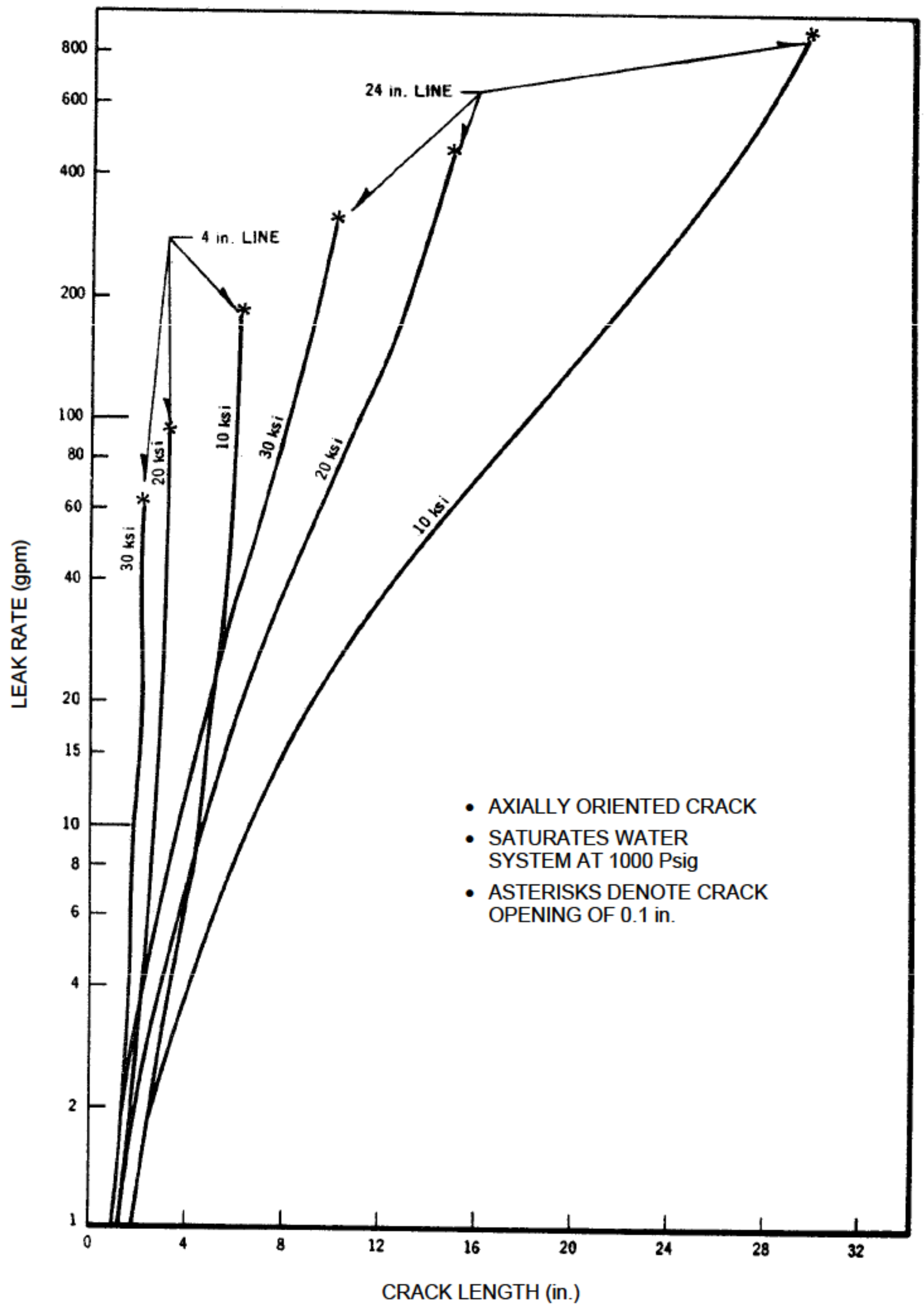
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SENSITIVITY OF PEAK RPV PRESSURE OF INITIAL PRESSURE FOR CODE OVERPRESSURE PROTECTION EVENT

FIGURE 5.2-5



REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CALCULATED LEAK RATE AS A FUNCTION OF CRACK LENGTH AND APPLIED HOOP STRESS

FIGURE 5.2-6

5.3 THERMAL-HYDRAULIC SYSTEM DESIGN

5.3.1 ANALYTICAL METHODS AND DATA

The analytical methods, thermodynamic and hydrodynamic data, used to determine the thermal and hydraulic characteristics of the reactor coolant system are presented in section 4.4.

5.3.2 OPERATING RESTRICTIONS ON PUMPS

The operating restrictions imposed on the coolant pump to meet net positive suction head requirements are contained in paragraph 4.4.3.2.

5.3.3 POWER-TO-FLOW OPERATING MAP

A power-to-flow operating map which indicates the permissible operating range is shown in figure 15.1-3.

5.3.4 TEMPERATURE-POWER OPERATING MAP FOR PRESSURIZED WATER REACTOR

This subsection is not applicable to a boiling water reactor.

5.3.5 LOAD FOLLOWING CHARACTERISTICS

Load following is not used at Plant Hatch.

5.3.6 TRANSIENT EFFECTS

The transient effects are presented in section 4.4 and chapter 15.

5.3.7 THERMAL AND HYDRAULIC CHARACTERISTICS SUMMARY TABLE

Thermal and hydraulic characteristics of the initial core are summarized in table 4A-5.

5.4 REACTOR PRESSURE VESSEL AND APPURTENANCES

5.4.1 PROTECTION OF CLOSURE STUDS

The Hatch Nuclear Plant-Unit 2 (HNP-2) design and inspection procedures are in conformance with the requirements of Regulatory Guide 1.65 (October 1973) except those in Regulatory Positions 2b, 2e, and 3.

Studs were examined in accordance with the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, N-325; (1968 Edition plus Summer 1970 Addendum in effect at the time of the contract). Bored blank nuts were ultrasonically examined by both the longitudinal and shear wave methods. Shear wave examination of the nuts was performed in both the axial and circumferential directions.

Regulatory Position 3 recommends provision for adequate corrosion protection during venting and filling of the vessel, and while the head is removed. General Electric (GE) supplies thread protectors which prevent stud damage, but stud holes are not plugged, and neither stud nor flange threads are protected from exposure to water. In practice, this has been found to be adequate, as exposure to applied loads and operating and servicing environments has not required the replacement of any boiling water reactor (BWR) studs or flange threads. No corrosion protection for studs is provided.

5.4.2 SPECIAL PROCESSES FOR FABRICATION AND INSPECTION

In addition to the normal radiographic techniques for inspection of welds, ultrasonic techniques were used in accordance with Section III of the ASME Boiler and Pressure Vessel Code.

5.4.3 FEATURES FOR IMPROVED RELIABILITY

No special design or fabrication features were required for the HNP-2 reactor pressure vessel (RPV) to improve its reliability or reduce its potential for failure.

5.4.4 QUALITY ASSURANCE SURVEILLANCE

The RPV was fabricated for GE by Combustion Engineering and was subject to Georgia Power Company (GPC) quality assurance (QA) audit.

QA surveillance procedures were used to ensure that purchased material, equipment, and services associated with the RPV and appurtenances conformed to the requirements of the purchase documents. These procedures include provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished, inspection at the vendor source, and examination of the RPV upon delivery at the construction site.

5.4.5 MATERIALS AND INSPECTIONS

The materials which were used in the RPV are listed in table 5.2-6.

The RPV was subject to the inspection requirements in accordance with Section III of the ASME Boiler and Pressure Vessel Code, 1968 edition plus summer 1970 addendum, and the ultrasonic inspection discussed in subsection 5.4.2.

5.4.6 REACTOR PRESSURE VESSEL DESIGN

5.4.6.1 Safety Design Bases

The RPV and appurtenances are designed to:

A. Withstand adverse combinations of loading and forces resulting from operation under abnormal and accident conditions.

B. Minimize the possibility of brittle fracture of the nuclear system process barrier by the following:

  1. Maximum impact properties at temperatures related to RPV operation were specified for materials used in the RPV.

  2. Expected shifts in nil ductility transition temperature (NDTT) during design service life as a result of environmental conditions, such as neutron flux, were considered and employed in the design.

  3. Operational margins to be observed with regard to the NDTT were specified for each mode of operation.

5.4.6.2 Power Generation Design Basis

The RPV and appurtenances are designed:

- For a minimum useful life of 40 years. Aging management programs (subsections 18.2.1, 18.2.9, 18.2.12, 18.2.15, and 18.2.17) monitor the condition of the reactor vessel so that actions are taken to provide reasonable assurance that the vessel is capable of performing its intended function for 40 years and beyond.

- So that stresses in the RPV and supports that result from reactions at external and internal supports that are part of the RPV are within ASME Code limits.

- To allow for a suitable program of inspection and surveillance.

5.4.6.3 Description

5.4.6.3.1 Reactor Pressure Vessel

The RPV, shown in figure 4.1-1, is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The vessel design data are listed in table 5.4-1.

The RPV is designed, fabricated, tested, inspected, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class A (1968 edition plus summer 1970 addendum). Design of the RPV and its support system meets Seismic Category I equipment requirements.

The cylindrical shell and bottom head of the RPV are fabricated of low-alloy steel, the interior of which is clad with stainless steel weld overlay. Internal surfaces of nozzles that connect to stainless steel pipe are also clad. The feedwater cladding was subsequently removed. See paragraph 5.4.6.3.9.

Inplace annealing of the RPV because of radiation embrittlement is unnecessary, as described in paragraph 5.2.4.5.

QA methods used during the fabrication and assembly of the RPV and appurtenances ensure that design specifications are met.

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

Thermocouples are located on the exterior of the RPV. At other thermocouple locations, two 3/4-in. pads are provided. One is an end pad to hold the end of a 3/16-in.-diameter thermocouple and the other is a clamp pad equipped with a set screw to secure the thermocouple. These thermocouple locations provide a means of observing RPV temperature in response to changes in RPV coolant flowrate. Because RPV metal thickness and the thermal time constant cause the temperature of the RPV surface to lag the coolant temperature, measurements of surface temperature do not afford an effective means of controlling thermal stresses in the RPV.

Procedural controls on plant operation are necessary to hold these thermal stresses within acceptable ranges. These restrictions on coolant temperature are:

A. The average rate of change of reactor coolant temperature during normal heatup and cooldown does not exceed 100°F during any 1-h period.

B. The RRS pumps are not operated unless the coolant temperatures in the upper and lower regions of the RPV are within 145°F of each other.

C. The pump in an idle RRS loop is not started unless the coolant temperature in that loop is within 50°F of reactor coolant temperature.

The limit regarding the normal rate of heatup and cooldown described in item A ensures that the RPV closure, closure studs, RPV support skirt, control rod drive (CRD) housing, and stub tube stresses and usage remain within acceptable limits. The RPV temperature limit on RRS pump operation restriction described in item B augments the item A limit by ensuring that the RPV bottom head region is not warmed at an excessive rate caused by rapid sweep-out of cold coolant in the RPV lower head region by RRS pump operation. Cold coolant can accumulate as a result of CRD inleakage and/or low recirculation flowrate during startup or hot standby. The item C limit further restricts operation of the RRS pumps to avoid high thermal stress effects in pumps and piping while also minimizing thermal stresses on the vessel nozzles.

5.4.6.3.2 Shroud Support

The reactor vessel shroud is a cylindrical shell that surrounds the reactor core assembly and provides a barrier to separate the upward core flow from the downcomer annulus flow. The shroud support is a circular plate welded to the RPV wall. This support is designed to carry the weight of the shroud, shroud head, core support plate, top guide, the steam separators, the jet pump system, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME Code stress limits.

5.4.6.3.3 Reactor Pressure Vessel Supports (Refer also to supplement 6A)

5.4.6.3.3.1 **Vessel Support Assembly.** The RPV support pedestal consists of two concentric steel shells 18 ft 3 in. and 26 ft 3 in. in diameter with concrete fill in between the shells to provide mass and stability. Stiffeners are provided at different locations to distribute the load uniformly over larger areas of the shell. The bottom of the pedestal is anchored to the base slab by means of ninety-two 3-in. diameter A 193 B7 anchor bolts which transfer the loads to the foundation. The top surface of the pedestal is machined and bolt holes are drilled using an identical template that is used for the RPV support skirt which is bolted to the top of the pedestal. Provisions are made at the top of the inner shell to inspect the reactor vessel bolting rings. Details of the RPV support pedestal are described in subsection 3.8.3.

5.4.6.3.3.2 **Reactor Pressure Vessel Stabilizers.** The RPV stabilizers are designed to permit radial and axial vessel expansion, to limit horizontal vibration, and to resist seismic and jet reaction forces. The stabilizers are connected between the RPV and the top of the shield wall surrounding the RPV to provide lateral stability for the upper part of the RPV. Six stabilizer brackets are attached by full penetration welds to the RPV at evenly spaced locations around the RPV below the flange. Each RPV stabilizer consists of a stabilizer rod threaded at the ends, springs, washers, a nut, a plate, and a bumper bracket with tapered shims. The stabilizers are

attached to each bracket and apply tension in opposite directions. The stabilizers are evenly preloaded with tensioners to the values of the residual loads.

5.4.6.3.4 Control Rod Drive Housings

The CRD housings are inserted through the CRD penetrations in the RPV bottom head and are welded to stub tubes extending into the RPV. Each housing transmits a number of loads to the bottom head of the reactor. These loads include the weights of a control rod, a CRD, a control rod guide tube, a four-lobed fuel support piece, and the four fuel assemblies that rest on the fuel support piece. The housings are fabricated of Type 304 austenitic stainless steel.

5.4.6.3.5 Control Rod Drive Housing Supports

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

5.4.6.3.6 Incore Neutron Flux Monitor Housings

Each incore neutron flux monitor housing is inserted through the incore penetrations in the bottom head of the RPV and is welded to the inner surface of the bottom head.

An incore flux monitor guide tube is welded to the top of each housing, as described in subsection 4.2.2. Either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal-ring flange at the bottom of the housing, as described in subsection 4.2.2.

5.4.6.3.7 Refueling Bellows

The refueling bellows forms a seal between the RPV and the surrounding primary containment drywell to permit flooding of the space (reactor well) above the RPV during refueling operations. The refueling bellows assembly consists of a Type 304 stainless steel bellows, a backing plate, a spring seal, and a removable guard ring. The backing plate surrounds the outer circumference of the bellows to protect it and is equipped with a tap for testing and for monitoring leakage. The self-energizing spring seal is located in the area between the bellows and the backing plate. This seal is designed to limit water loss in the event of a bellows rupture by yielding to make a tight fit to the backing plate when subjected to full hydrostatic pressure. The guard ring attaches to the assembly and protects the inner circumference of the bellows. The guard ring can be removed from above to inspect the bellows. The assembly is welded to the reactor bellows support skirt and the reactor well seal bulk-head plate. The reactor bellows support skirt is welded to the RPV shell flange. The reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. Six watertight hinged covers are bolted in place for normal refueling operation. For normal operation, these covers are opened and

removable air supply ducts and air return ducts permit circulation of ventilation air in the region above the reactor well seal.

5.4.6.3.8 Reactor Pressure Vessel Insulation

The reactor vessel insulation has an average maximum heat transfer rate of ~ 0.2 Btu/h/ft^2/°F at the operating conditions of 551.7°F for the vessel and 135°F for the drywell air. The drywell average air temperature limit for normal operation is ≤ 150°F. The insulation panels for the cylindrical shell of the RPV are held in place by resting on circumferential steel rings which have welded brackets which are in turn welded to the biological shield. The insulation is designed to be removable where inspection is required by the inservice inspection code. Shell course welds are inspected remotely.

5.4.6.3.9 Reactor Pressure Vessel Nozzles

All piping connecting to the RPV nozzles, including instrument piping, has been designed so as not to exceed the allowable loads on any nozzle.

The RPV nozzles are low-alloy steel forgings made in accordance with the ASME Code A508. Nozzles of nominal size larger than 3-in. are full-penetration welded to the vessel. Nozzles of 3-in. nominal size and under may be partial penetration welded, as permitted by ASME Boiler and Pressure Vessel Code, Section III. Nozzles which are partial penetration welded are nickel-chromium-iron forgings made in accordance with ASME Code SB 166 or SB 167.

The RPV top head nozzles are provided with flanges with small groove facing. The drain nozzle is of the full penetration weld design and extends below the bottom outside surface of the RPV. The RRS inlet nozzles, feedwater inlet nozzles, and core spray inlet nozzles all have thermal sleeves similar to those shown in the detail in figure 5.4-1. Information on feedwater nozzle blend radii cracking is provided in NEDO-21821 (NEDE-21821), "Boiling Water Reactor Feedwater Nozzle/Sparger Final Report," and Supplement to that report. The HNP-2 feedwater thermal sleeves and nozzles are the welded-in design and are fully described in NEDO-21821 (NEDE-21821) and their supplements.

Nozzles connecting to stainless piping have safe-ends made of stainless steel. These safe-ends are welded to the nozzles after the RPV has been heat treated to avoid furnace sensitization of the stainless steel.

The nozzle for the core differential pressure and liquid control pipe is designed with a transition so that the stainless steel outer-pipe of the differential pressure and liquid control line can be socket-welded to the inner end of the nozzle and so that the inner pipe passes through the nozzle. This design provides an annular region between the nozzle and the inner liquid control line to minimize thermal shock effects on the RPV in the event that use of the standby liquid control system is required.

5.4.6.4 Safety Evaluation

The RPV design pressure of 1250 psig is based on an analysis of margins required to provide a reasonable operating range. The margins include additional allowances to accommodate transients above the operating pressure (~ 1048 psig at the level of the top head flange) without initiating safety relief valve action. The RPV design temperature of 575°F is based on the saturation temperature of water that corresponds to the design pressure.

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

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

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

The following calculations are used to determine the CUF for each of the limiting RPV components. In addition, a license renewal commitment includes evaluation of the locations identified in NUREG/CR-6260 using the applicable environmental fatigue correlations provided in NUREG/CR-6909. The applicable RPV locations for Unit 2 are:

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

<u>RPV Main Closure Studs</u>

$$Usc = Xcs + (520.75n_1 + 60.32n_2 + 115.87n_3 + 28.57n_4 + 34.92n_5 + 11.11n_6 + 15.38n_7) \times 10^{-5}$$

where:

Usc	=	new CUF
Xcs	=	most recently calculated CUF
n_1	=	no. of boltups
n_2	=	no. of hydrostatic tests to 1250 psig
n_3	=	no. of cooldowns from > 488°F (600 psig) to < 470°F (500 psig)
n_4	=	no. of rapid cooldowns at rates > 100°F/h
n_5	=	no. of rapid heatups at rates > 100°F/h
n_6	=	other scrams (manual scrams that are not performed during shutdown)

n_7 = no. of cooldowns from 551°F (1040 psig) > 20°F to 470°F (500 psig) or above

(n_1 through n_7 equals the number of event types during the surveillance period).

RPV Shell

$Us = Xs + (43.48n_1 + 3.33n_2) \times 10^{-5}$

where:

Us = new CFUF
Xs = most recently calculated CFUF
n_1 = no. of boltups in the surveillance period
n_2 = no. of any heatups or cooldowns > 100°F during the surveillance period

To address CUF with environmental effects considered for the RPV shell, the CUF determined above is multiplied by an environmental factor (Fen) of 12.61.

RPV Recirculation Inlet Nozzles

With Environmental Effects:

U = n1/(8688.35/10.95) + n2/(22493.75/10.95) + n3/(32594.69/10.95) + n4/(41757.69/10.95) + n5/(46789.01/10.95) + n6/(49232.17/10.95) + n7/(50649.57/10.95) + n8/(59290.86/10.95) + n9/(87746.98/10.95) + n10/(618015.52/10.95) + n11/(49233596.10/10.95)

Without Environmental Effects:

$Ur = n_1/8688.35 + n_2/22493.75 + n_3/32594.69 + n_4/41757.69 + n_5/46789.01 + n_6/49232.17 + n_7/50649.57 + n_8/59290.86 + n_9/87746.98 + n_{10}/618015.52 + n_{11}/49233596.10$

where:

Ur = New CUF
n_1 = Loss of AC power natural circulation restart
n_2 = Loss of AC power natural circulation restart
n_3 = Hydrostatic test + Hydrostatic test to 1563 psig (= Hydrostatic test + Hydrostatic test to 1563 psig - n2 - n1)
n_4 = Loss of AC power natural circulation restart
n_5 = Turbine trip
n_6 = Shutdown (= Shutdown - n5 - n4 - n3)
n_7 = Scram: turbine generator (TG) trip + Scram: all other (=Scram: turbine generator (TG) trip + Scram; all other - n6)
n_8 = Startup (Startup - n7)
n_9 = Loss of AC power natural circulation restart
n_{10} = Scram; turbine generator (TG) trip + Scram: all other
n_{11} = Pre Op blowdown

Note: Number of cycles (n) cannot be negative. If a combination of transients results in a negative value for any n, then the value of that n is set to zero in the usage calculation.

RPV Feedwater Nozzles

$U_f = X_f + (7.338 \times 10^{-4}) x(n_1 + n_2)$

where:

U_f = new CUF
X_f = most recently calculated CUF
n_1 = no. of startups during the surveillance period
n_2 = no. of scrams during the surveillance period

The Unit 2 RPV feedwater nozzle must be evaluated and shown acceptable using the applicable environmental fatigue correlations provided in NUREG/CR-6909 prior to June 13, 2018.

These areas have been shown by analysis to have the highest CUF predictions over the life of the RPV. All other areas of the RPV have been analyzed to have a negligible effect on the fatigue of the RPV and thus are not monitored. The methodology used for calculating the CUFs is contained in the GE report, "Reactor Pressure Vessel Thermal Cycle Evaluation for Edwin I. Hatch Nuclear Power Station Units 1 and 2," GPC-103-1, DRF:B11-00362, August 1986, GE Letter GEH-042, "Hatch 1 & 2 Extended Power Uprate Cumulative Fatigue Usage Formulas," August 13, 1997, "Fatigue Analysis for the Recirculation Inlet Nozzles and Main Closure Studs, Edwin I. Hatch Nuclear Power Station Unit 1," GE-NE-523-103-0793, Rev. 0, DRF 137-0010-6, and "Cycle-Based Fatigue Development for Select Hatch Locations," Structural Integrity Calculation Package 1001182.301, Rev. 2, 9/30/2013. This methodology is reflected in the fatigue monitoring software and the fleet procedures for CUF monitoring, and is performed at least once per operating cycle. Stress evaluation for the RPV has also been performed for thermal power level of 2804 MWt and reactor operating pressure of 1060 psia.[1, 2]

5.4.7 REACTOR PRESSURE VESSEL SCHEMATIC

The RPV schematic is shown in figure 5.4-2.

REFERENCES

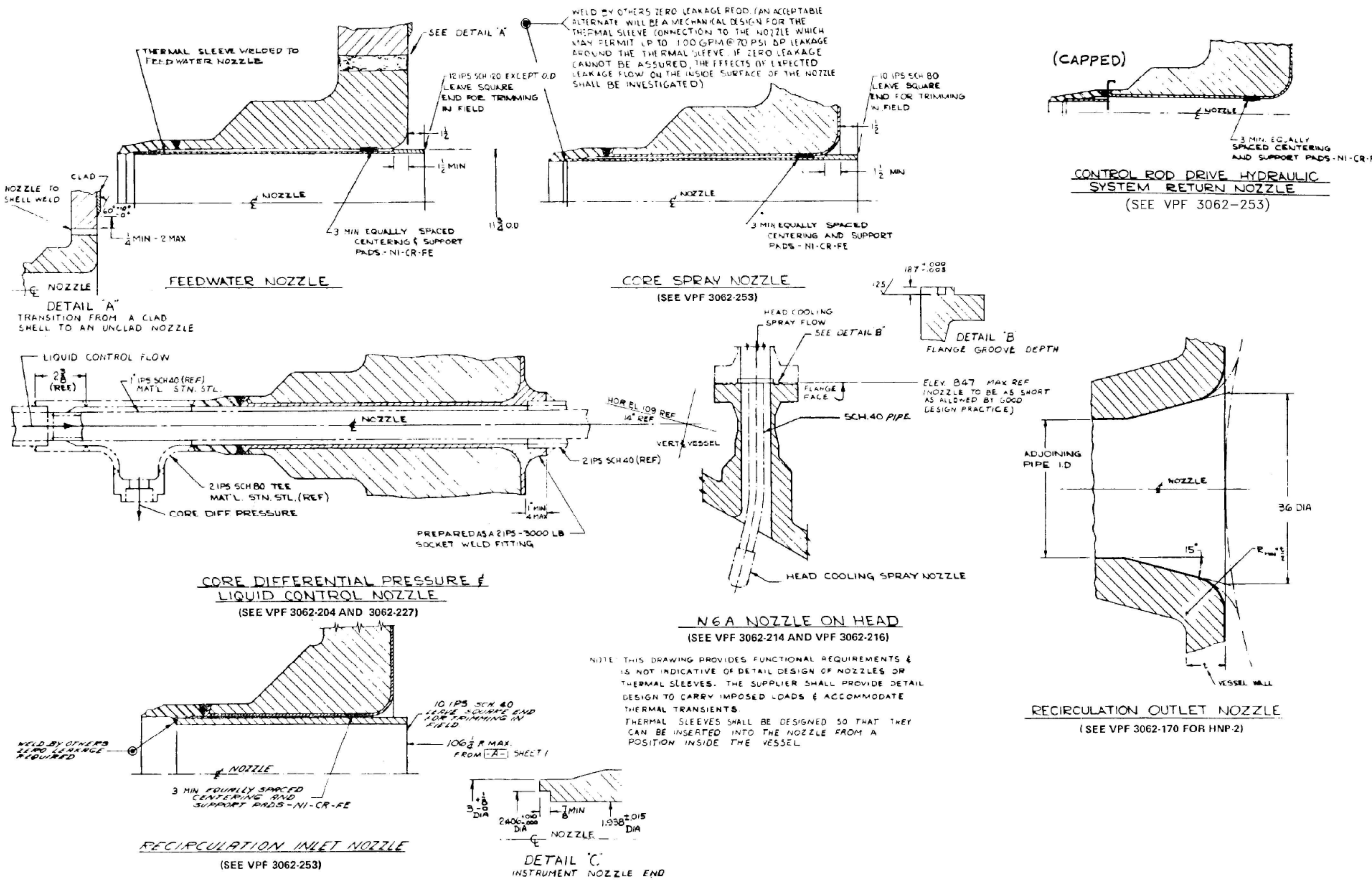
1. “Safety Analysis Report for Edwin I. Hatch Units 1 and 2 Thermal Power Optimization,” NEDC-33085P, GE Nuclear Energy, December 2002.

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

TABLE 5.4-1

REACTOR PRESSURE VESSEL DESIGN DATA

Reactor Pressure Vessel	
Inside diameter (in.) (minimum)	218
Inside length (including closure head)	68 ft 8 in.
Design pressure and temperature (psig @ °F)	1250 @ 575
Reactor Pressure Vessel Support	
Design horizontal seismic shear (kips)	252
Design seismic moment (ft-kips)	7016
Vessel Nozzles [No./Size (in.)]	
Recirculation outlet	2/28
Steam outlet	4/24
Recirculation inlet	10/12
Feedwater inlet	4/12
Core spray inlet	2/10
CRD	137/6
Jet pump instrumentation	2/4
Vent	1/4
Instrumentation	6/2
Head spray (spare connections)	2/6
Drain	1/2
CRD hydraulic system return	1/3
Core differential pressure and liquid control	1/2
Incore flux instrumentation	43/2
Head seal leak detection	2/1



ACAD 2050401

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

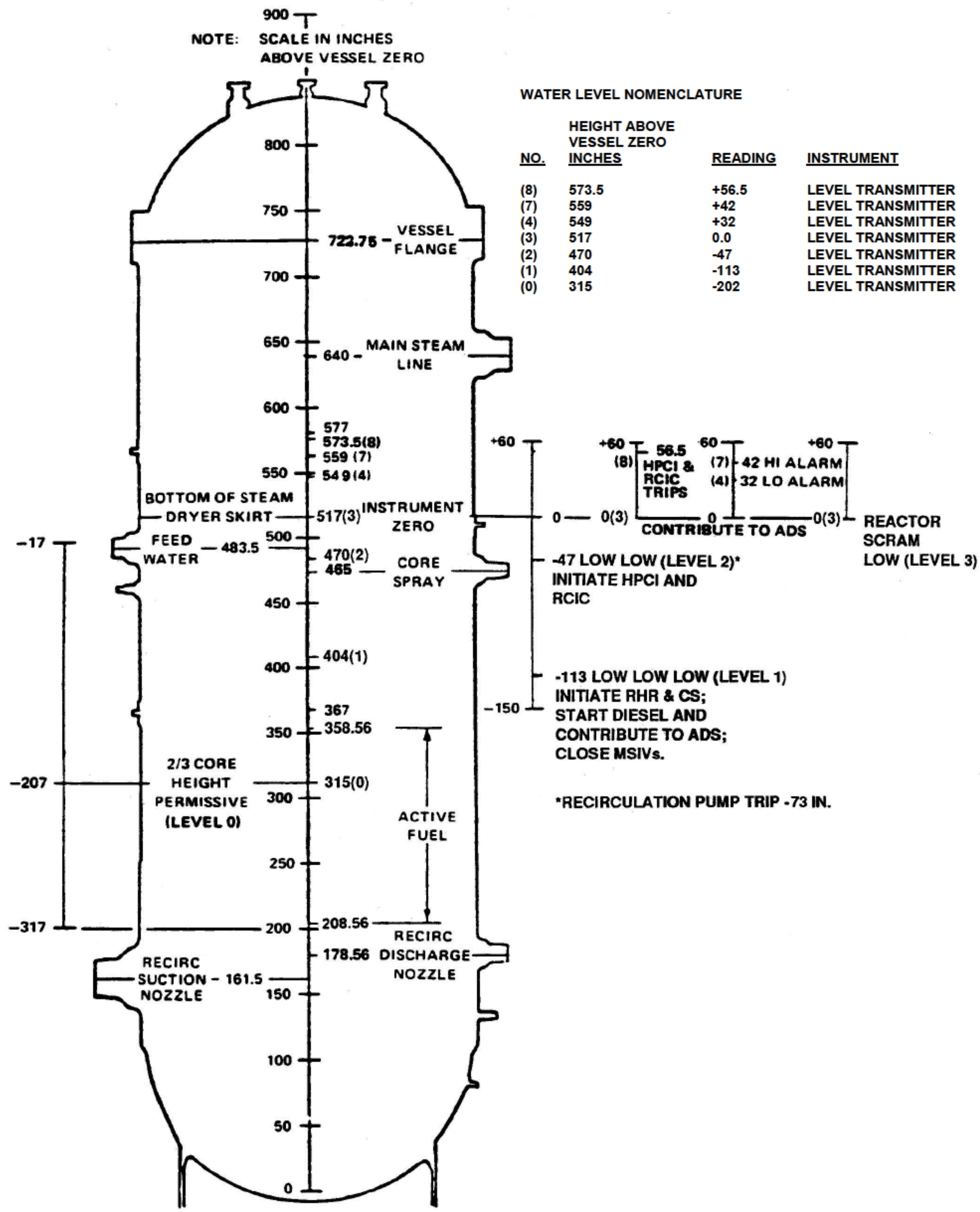
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

REACTOR VESSEL NOZZLES AND PENETRATIONS

FIGURE 5.4-1

WATER LEVEL NOMENCLATURE

NO.	HEIGHT ABOVE VESSEL ZERO INCHES	READING	INSTRUMENT
(8)	573.5	+56.5	LEVEL TRANSMITTER
(7)	559	+42	LEVEL TRANSMITTER
(4)	549	+32	LEVEL TRANSMITTER
(3)	517	0.0	LEVEL TRANSMITTER
(2)	470	-47	LEVEL TRANSMITTER
(1)	404	-113	LEVEL TRANSMITTER
(0)	315	-202	LEVEL TRANSMITTER



REV 21 7/03

SOUTHERN COMPANY *Energy to Serve Your World®*

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

REACTOR VESSEL SCHEMATIC

FIGURE 5.4-2

5.5 COMPONENT AND SUBSYSTEM DESIGN

This section presents discussions of the performance requirements and design features to ensure overall safety of the various components within the reactor coolant pressure boundary (RCPB) and those subsystems closely allied with the reactor coolant system (RCS) but not a portion of the RCPB. The subsystems and components discussed in this section are the reactor recirculation system (RRS), reactor core isolation cooling (RCIC) system, residual heat removal (RHR) system, reactor water cleanup (RWC) system, main steam lines and feedwater piping from the reactor pressure vessel (RPV) out to the first isolation valve including drains, valves, and component supports. The portions of these subsystems which are within the RCPB are discussed in sections 5.1 through 5.4.

5.5.1 RRS AND PUMPS

5.5.1.1 Safety Design Bases

The RRS is designed to:

- Ensure an adequate fuel barrier thermal margin during postulated transients.
- Not compromise the ability of the RPV internals to provide a refloodable volume should a failure of piping integrity occur.
- Maintain pressure integrity during adverse combinations of loadings and forces occurring during anticipated operational occurrence (AOO), accident, and special event conditions.

5.5.1.2 Power Generation Design Bases

The RRS is designed to:

- Provide sufficient flow to remove heat from the fuel over the entire load range.
- Provide an automatic load-following capability over the range of 65 to 100% rated power (see paragraph 7.1.1.2).
- Minimize maintenance situations that would require core disassembly and fuel removal.

5.5.1.3 System Description

The RRS consists of the two RRS pump loops external to the RPV. These loops provide the piping path for the driving flow of water to the RPV jet pumps, as shown on figure 5.5-1 and

drawing no. H-26003. Each external loop contains one variable-speed motor-driven RRS pump, two motor-operated gate valves, and an adjustable speed drive (ASD) to control RRS pump speed. Each pump discharge line contains a venturi-type flow meter nozzle.

The RRS loops are part of the nuclear system process barrier and are located inside the primary containment structure. The jet pumps are RPV internals. Their location and mechanical design are discussed in subsection 4.2.2. However, certain operational characteristics of the jet pumps are discussed in this subsection. Table 5.5-1 summarizes the design characteristics of the RRS.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the RPV wall and the core shroud. A portion of the coolant flows from the RPV through the two external RRS loops and becomes the driving flow for the jet pumps. Each of the two external RRS loops discharges high-pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the RPV. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section shown in figure 5.5-2. The adequacy of the total flow to the core is discussed in subsection 4.4.4. Documented tests show that the jet pump design is sound and that jet pump operation is stable and predictable.

There is actually a very low probability that an RRS loop that has been allowed to cool would need to be placed in service again when the nuclear system is hot. The only valid reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the RRS loop between the valves, e.g., excessive leakage through the pump mechanical seal. A leak of this nature cannot be repaired without permitting access to the drywell. The nuclear system would in all probability be cooled prior to repair of the leak.

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

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

The RRS pumps can be operated at low speeds during nuclear steam supply system (NSSS) heatup for hydrostatic tests. At this time, they act in conjunction with any contribution from reactor core decay heat to raise NSSS temperature above the limit imposed on the RPV by nil ductility transition temperature considerations so the hydrostatic test can be conducted.

Each RRS pump is a single-stage, variable-speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies.

The RRS pump shaft seal assembly consists of two individual seals built into a cartridge which can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or is operating at various speeds, with water at various pressures and temperatures. Each seal is designed for a life of 1 year based on a 90% probability factor. Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal should fail. A breakdown orifice is provided in the pump casing to reduce leakage in the event of a gross failure of both shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow-measuring device which alarms on high leakage.

Each RRS pump motor is a variable-speed ac electric motor which can drive the pump over a controlled range of 20 to 100% of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 Hz. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of National Electrical Manufacturers Association standards.

A variable-frequency ASD located outside the drywell supplies power to each RRS pump motor. The pump motor is electrically connected to the ASD and is started when the ASD is energized. Minimum speed corresponds to a frequency of 11.5 Hz.

The combined rotating inertias of the RRS pump and motor are chosen to provide an acceptable coastdown of flow following loss of power to the drive motors so that the core is adequately cooled during AOOs. The effective inertias of these devices are specified in the following form, which takes into account the torque and speed conditions on each rotating shaft:

$$\sum_{\substack{\text{All} \\ \text{shafts}}} \left[\frac{\text{Inertia (lb-ft}^2\text{) x speed (radian/s)}}{\text{g(ft/s}^2\text{) x (torque ft-lb)}} \right]$$

The design objective for the RRS pump internals is to provide a unit that does not require removal from the system for rework or overhaul at intervals of < 5 years. Erosion, corrosion, and material fatigue were accounted for in the design of the pump casings and valve bodies. Aging management programs (subsections 18.2.1, 18.2.6, 18.2.12, 18.3.2, and 18.5.1) monitor the condition of the pumps and valves so that actions are taken to provide reasonable assurance that these components are capable of performing their intended functions for 40 years and beyond. The pump drive motor, impeller, and wear rings are designed for as long a life as is practical. Pump mechanical-seal parts are expected to have a life exceeding 1 year to afford convenient replacement during refueling outages.

The original RRS piping made from Type 304 stainless steel material was replaced with Type 316 nuclear grade material. The replaced RRS is of all-welded construction but is modified to reduce the number of welds; i.e., no end caps, no contour nozzles, one-piece

cross-reducer-tee, and use of extra-long tangent elbows in lieu of an elbow and a short pipe spool. The replaced RRS is designed to meet the requirements of the 1980 ASME Boiler and Pressure Vessel Code, Section III, Class 1, with Addenda through Winter 1981 and is constructed to the 1980 Edition of the ASME Boiler and Pressure Vessel Code, Section III, Class 1, with Addenda through Winter 1980.

Except for the ASD, the RRS is designed as Seismic Category I. The pump is assumed to be filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist horizontal reactions.

The RRS piping, valves, and pumps are supported by constant-support and variable-support hangers to avoid the use of expansion loops that would be required if the pumps were anchored. In addition, the RRS loops are provided with a system of restraints designed so that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. Because possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement, no impact loading on limit stops is considered.

The RRS piping, valves, and pump casings are covered with thermal insulation which is a glass fiber-type insulation comprised of a flexible light-density, fibrous glass pad insulation and encapsulated in woven glass cloth forming a composite blanket. The blanket is then covered by stainless-steel jackets and a mechanism for locating and identifying each weld under the insulation. Removable insulation sections are provided at all field welds to facilitate periodic inspection as required by ASME Boiler and Pressure Vessel Code, Section XI rules for inservice inspection of nuclear reactor coolant systems.

5.5.1.4 Safety Evaluation

RRS malfunctions that pose threats of damage to the fuel barrier are described and evaluated in section 15.2. It is shown in section 15.2 that none of the malfunctions result in fuel damage. The RRS has sufficient flow coastdown characteristics to maintain fuel thermal margins during AOOs.

Figure 5.5-3 shows the core flooding capability provided by a jet pump design plant. No recirculation line break can prevent reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of the RRS and of a jet pump design plant is discussed in reference 1 and in section 15.2.

Piping and pump design pressures for the RRS are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the RRS loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the applicable code design criteria, tabulated in section 3.9, ensures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

General Electric (GE) purchase specifications require that the RRS pump's first critical speed be not < 130% of operating speed. GE purchase specifications also require that integrity of the pump case be maintained through all transients and that the pump remain operable through all normal and upset transients. The design of the pump and motor bearings is required to be such that the dynamic load capability at rated operating conditions is not exceeded during the design basis earthquake (DBE).

The hypothetical loss of component cooling water to the RRS pumps was examined and is tabulated below (drawing no. H-26003):

A. Closed Cooling Water to Pump Motor Bearings and Windings

Assumptions: Closed cooling water is stopped.

Sequence of events

Low flow alarm from FS N008 (windings)

High temperature alarms

TE N009	-	Motor winding cooling water discharge
TE N001	-	Motor bearing oil cooling water discharge
TE B_1, B_2	-	Motor thrust bearing lower face
TE A_1, A_2	-	Motor thrust bearing upper face
TE C_1, C_2	-	Upper guide bearing
TE D_1, D_2	-	Motor winding A
TE E_1, E_2	-	Motor winding B
TE F_1, F_2	-	Motor winding C
TE G_1, G_2	-	Lower guide bearing

If the operator ignores all these alarms, bearing damage occurs in 10 to 15 min.

The pump continues to run until a winding short occurs due to excessive winding temperature. This causes an immediate pump trip.

B. Closed Cooling Water to Pump Seals

Assumption: Closed cooling water is stopped.

Sequence of events

Low-flow alarm from FS N004

Seal purge provides enough cooling to keep the seal cavities from heating up enough to cause damage to the seals.

C. Seal Purge Water

Assumption: Control rod drive (CRD) system water is stopped.

Sequence of events

Seal flow reverses due to the decrease in pressure in the seal cavities. The seal cavity temperatures increase slightly due to the entry of reactor water. The pump seal cooling system removes this additional heat.

D. Pump Seal Cooling Water and Seal Purge Water

Assumptions:

1. Closed cooling water is stopped.

2. CRD system water is stopped.

Sequence of events

Low-flow alarm from FS N004

Seal cavities start to heat up due to loss of cooling.

Temperature alarms

TE N003 - Pump seal flow

Seal cavity temperatures

No. 1 cavity

No. 2 cavity

Seals start to deteriorate, increasing leakage into No. 2 cavity and eventually out of No. 2 cavity.

- Seal staging high-flow alarm - FS N007

- Seal leak detection high-flow alarm - FS N002

The pump continues to operate until the reactor is shut down due to high identified leakage in the drywell, or the pump is tripped and isolated to reduce the leakage.

Since the failures discussed in items A through D produce no consequences that are important to reactor safety, it is not necessary to provide a single-failure proof cooling water system.

Additional discussion is contained in NEDO-24083, Recirculation Pump Shaft Seal Leakage Analysis.

Analyses were also performed to investigate the possibility of the RRS pump becoming a missile during the postulated double ended pipe break in the RRS pump suction or discharge lines.

This analysis demonstrates that for the complete spectrum of breaks in piping on the discharge side of the recirculation pump, no overspeed conditions exist. The study indicates by conservative analysis that in the unlikely event of a completely offset guillotine suction break, potential overspeed may be calculated. However, further considerations support the conclusion that this calculated overspeed condition would not realistically create an unsafe condition. As a result, there is no need for protective equipment on the recirculation pumps in GE boiling water reactors (BWRs).

5.5.1.5 Tests and Inspections

Quality control methods are used during fabrication and assembly of the RRS to ensure that design specifications are met. Tests and inspections are carried out as described in chapter 14.

The RCS was thoroughly cleaned and flushed before fuel was loaded initially and after replacement of the recirculation piping system.

During the preoperational test program, the RRS was hydrostatically tested at 125% reactor vessel design pressure. See paragraph 3.9.1.1.1 for the restart test program after the recirculation pipe replacement. Preoperational tests on the RRS also include checking for proper operation of the valves. Pumps and motor-generator sets are preoperationally tested, and operation of the flow-control system is checked.

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

A hydrostatic test at a pressure not to exceed system operational pressure is made following each removal and replacement of the reactor vessel head.

Inservice inspection is considered in the design of the RRS to ensure adequate working space and access for inspection of selected components in accordance with the ASME Boiler and Pressure Vessel Code, Section XI. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location,

including areas of known stress concentrations and locations where cyclic strain or thermal stress might occur. The RRS pump casings, valve bodies, and piping connection welds are visually inspected and given other nondestructive inspections from at least one side on a periodic basis.

5.5.2 STEAM GENERATORS

Steam generators are not applicable to a BWR.

5.5.3 REACTOR COOLANT PIPING

The RRS piping is discussed as part of the RRS in subsection 5.5.1. The RRS loops are shown on figure 5.5-1 and drawing no. H-26003. The design characteristics are presented in table 5.5-1.

5.5.4 MAIN STEAM LINE FLOW RESTRICTORS

5.5.4.1 Safety Design Bases

The main steam line flow restrictors are designed to:

- Limit the loss of coolant from the RPV following a steam line rupture outside the primary containment to the extent that the RPV water level does not fall below the top of the core within the time required to close the main steam isolation valves (MSIVs).

- Withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line.

5.5.4.2 Description

A main steam line flow restrictor is provided for each of the four main steam lines, as shown in figure 5.5-4. The restrictor is a complete assembly welded into the main steam line. It is located between the RPV and first MSIV and is downstream of the main steam line safety relief valves. The restrictor limits the coolant blowdown rate from the RPV in the event a main steam line break (MSLB) occurs outside the primary containment to the maximum (choke) flow specified. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The flow restrictor is designed and fabricated to ASME Code, Section III.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with an MSLB. The maximum differential pressure is 1375 psi, the ASME Code limit. The rated capacity of the RPV pressure-relieving devices is sufficient to prevent a

rise in pressure within the protected vessel of more than 110% of the design pressure (1.10 x 1250 = 1375 psig).
The ratio of venturi-throat diameter to steam line diameter of approximately 0.5058 results in a maximum pressure differential of 10 psi at rated flow. This design limits the steam flow in a severed line to approximately 200% rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow and to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

5.5.4.3 Safety Evaluation

In the event a main steam line should break outside the primary containment, the critical flow phenomenon would restrict the steam flowrate in the venturi throat to 200% of rated value. Prior to isolation valve closure, the total coolant losses from the RPV are not sufficient to cause core uncovering. Thus, the core is adequately cooled at all times.

Analysis of the main steam line break accident (MSLBA) shows that the core remains covered with water and that the amount of radioactive material released to the environs through the MSLB does not exceed the guideline values of 10 Code of Federal Regulation (CFR) 50.67. The MSLBA analysis is described in section 15.3.

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

If moisture forms in the nozzle throat due to a momentary large static pressure reduction, the droplets of wet steam would have to be at saturation temperature corresponding to throat static pressure. When proceeding to the downstream region where vapor temperatures are higher, the droplets of wet steam vaporize somewhat and reach equilibrium with vapor at a lower pressure. The moisture is reduced and actually is negligible. It has negligible corrosion effect on the highly corrosion-resistant material (A351 stainless steel) being used for the inlet and throat sections. High-velocity steam also has negligible erosion effect on this material.

The steam-flow restrictor is exposed to steam of 0.1 to 0.2% moisture flowing at velocities of 150 ft/s (steam piping inside diameter) to 600 ft/s (steam restrictor throat). American Society of Testing Materials (ASTM) A 351 (Type 304) cast stainless steel was selected for the steam-flow restrictor material because it has excellent resistance to erosion-corrosion in this environment. The excellent performance of stainless steel in high-velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel which prevents any surface attack, and this film is not removed by the steam.

Surface finish has a minor effect on erosion-corrosion. Experience shows that a machined or a ground surface is sufficiently smooth and that no detrimental erosion occurs.

5.5.4.4 Tests and Inspections

The flow restrictor forms a permanent part of the main steam line piping and has no moving components. Only very slow erosion occurs with time, and such a slight enlargement has no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have shown no noticeable effects from erosion on the stainless steel nozzle partitions. Aging management programs (subsections 18.2.1 and 18.2.12) monitor the condition of the flow restrictors so that actions are taken to provide reasonable assurance that these components are capable of performing their intended function for 40 years and beyond.

5.5.5 MAIN STEAM LINE ISOLATION VALVES

5.5.5.1 Safety Design Basis

The MSIVs, individually or collectively, are designed to:

- Close the main steam lines within the time established by design basis accident (DBA) analysis to limit the release of reactor coolant.

- Close the main steam lines slowly enough that simultaneous (inadvertent) closure of all steam lines does not exceed NSSS design limits.

- Close the main steam lines when required, despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function.

- Use separate energy sources as the motive force to independently close the redundant isolation valves in the individual steam lines.

- Use local stored energy (compressed air and springs) to close at least one isolation valve in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure.

- Be able to close the steam lines, either during or after seismic loadings, to ensure isolation if the nuclear system is breached.

- Have the capability for being tested, during normal operating conditions, to demonstrate that the valves function.

5.5.5.2 Description

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

Figure 5.5-5 shows an MSIV. Each is a 24-in., Y-pattern globe valve. Design steam flowrate through each valve is 3.04 x 10^6 lb/h. The main disc or poppet is attached to the lower end of the stem and moves in guides at a 45-degree angle from the inlet pipe. Normal steam flow tends to close the valve, and higher inlet pressure tends to exert a higher closing force on the valve disk.

The stem disk attached to the end of the valve stem closes a small pressure-balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give a flow area past the wide-open poppet approximately equal to the seat port area. The poppet travels ~ 90% of the valve stem travel, and the last 10% of travel closes the pilot hole. A helical spring between the stem and the poppet keeps the pilot hole open when the poppet is off its seat, but failure of the spring does not prevent closure of the valve. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

The 45-degree angle permits the inlet and outlet passages to be streamlined. This minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at rated flow is ~ 7 psi. The valve stem penetrates the valve bonnet through a stuffing box that has replaceable packing. To help prevent leakage through the stem packing, the poppet backseats when the valve is fully open. The bonnet provides for seal welding in case leaks develop after the valve has had extensive service.

Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 5 s.

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

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

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder. This unit contains three types of control valves: pneumatic, ac control system A, and ac control system B. These control valves open and close the main valve and exercise it at slow and fast speed. Remote-manual switches in the main control room (MCR) enable the operator to operate the valves.

Operating air is supplied to the valves from the plant compressed-air system or nitrogen supply through a check valve. An accumulator tank between the control valve and the check valve provides backup operating air. Each valve is designed to accommodate saturated steam at 1250 psig and 575°F, with a moisture content of ~ 0.23%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm.

In the worst-case conditions of the main steam line rupturing downstream of the valve, steam flow would quickly increase to 200% of rated flow. Further increase is prevented by the venturi flow restrictor upstream of the valves.

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

The design objective for the valve is a minimum of 40-years service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.

Corrosion is accounted for in the design of the MSIVs. Aging management programs (subsections 18.2.1, 18.2.9, and 18.4.5) monitor the condition of the valves so that actions are taken to provide reasonable assurance that these components are capable of performing their intended functions for 40 years and beyond.

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

The MSIVs are designed to close under accident environmental conditions of 340°F for < 60 s at 65 psig.

In addition, they are designed to remain closed under the following post-accident environmental conditions:

- 340°F for 3 h at 45 psig.
- 320°F for an additional 3 h at 45 psig.
- 250°F for an additional 24 h at 25 psig.

- 200°F for an additional 100 days at 20 psig.

(Refer to the Plant Hatch Central File for the environmental requirements of the electrical portion of the MSIVs.)

To sufficiently resist the response motion from the DBE, the MSIV installations are designed as Seismic Category I equipment. The valve assembly is manufactured to withstand the design basis seismic forces applied at the mass center, assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously and are combined. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress set forth in the applicable codes. The parts of the MSIVs that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Boiler and Pressure Vessel Code, Section III, for Class I valves.

HNP-2 processes MSIV leakage which could leak through the closed MSIVs following a loss-of-coolant accident (LOCA). The leakage is directed from the MSIV through the main steam drain line to the isolated condenser where the leakage decays off and plates out. A description of the MSIV leakage treatment system is presented in section 9.5.10.

5.5.5.3 <u>Safety Evaluation</u>

In a direct-cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the reactor containments. Radioactive materials in the steam are released to the environs through process openings in the steam system or they escape from accidental openings. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steam line break outside the primary containment is described in chapter 15. The analysis shows that the fuel barrier is protected against loss of cooling if MSIV closure takes ≤ 5.5 s. This 5.5-s limitation includes as much as 0.5 s for the instrumentation to initiate valve closure after the break. The calculated radiological time effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

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

The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high-pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test

facilities. Dynamic tests with a 1-in. valve show that the analytical method is valid. A full-size, 20-in. valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions.[(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 between 3 and 5 s, each valve was tested at rated pressure (1000 psig) and no flow. The valve was stroked several times, and the closing time was recorded. The valve was closed by spring only and by the combination of air cylinder and springs.

B. Leakage was measured with the valve seated and backseated. Seat leakage was measured by pressurizing the upstream side of the valve. The specified maximum seat leakage, using cold water at design pressure, is 2 cc/h/in. of nominal valve size. Backseat leakage is 2 cc/h/in. of stem diameter. In addition, an air seat leakage test was conducted using 50-psi pressure upstream. Maximum permissible leakage is 0.1 sf^3/h/in. of nominal valve size. There must be no visible leakage from either set of stem packing at design pressure. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage must still be zero by visual examination.

C. Each valve was hydrostatically tested in accordance with the requirements of the draft ASME Nuclear Pump and Valve Code through Winter 1971. During valve fabrication, extensive nondestructive tests and examinations were conducted. Tests included radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hard facings, and bolts.

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

After the valves were installed in the NSSS, each valve was tested several times in accordance with the preoperational and startup test procedures. Two isolation valves provide redundancy in each steam line so that either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve and outside valve and their respective control systems are separated physically.

The isolation valves and their installation are designed as Seismic Category I equipment. The design of the isolation valve has been analyzed for earthquake loading. These loads are small compared with the pressure and operating loads that the valve components are designed to withstand. The cantilevered support of the air cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading is negligible at the joints between the support shafts and the valve bonnet.

Electrical equipment that is associated with the isolation valves and that operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The containment pressure and temperature transient following an accident is discussed in section 6.2.

5.5.5.4 Tests and Inspections

The MSIVs can be functionally tested for operability during plant operation and refueling outages. The test operations are listed below. During a refueling outage the MSIVs can be functionally tested, leaktested, and visually inspected. The MSIVs can be tested and exercised individually to the 90% open position because the valves still pass rated steam flow when 90% open.

The MSIVs can be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow in the remaining main steam lines through the flow restrictors.

Leakage from the valve stem packing becomes suspect during reactor operation from measurements of leakage into the primary containment or from observations or similar measurements in the secondary containment.

Any excessive leakage found is corrected, and the leak-rate measurement is repeated. During prestartup tests following an extensive shutdown, the valves receive the same hydrostatic tests (~ 1000 psi) that are imposed on the primary system.

Such a test and leakage measurement program ensures that the valves are operating correctly and that a leakage trend is detected.

5.5.6 RCIC SYSTEM

5.5.6.1 Safety Design Bases

The RCIC system is designed to:

- Ensure that adequate core cooling takes place to prevent the reactor fuel from overheating in the event that reactor isolation is accompanied by loss of flow from the reactor feedwater system.

- Withstand the effects of an earthquake without a failure.

5.5.6.2 Power Generation Design Bases

The RCIC system is designed to:

- Operate automatically in time to maintain sufficient coolant in the RPV so that the low-pressure emergency core cooling systems (low-pressure coolant injection (LPCI) and core spray (CS) systems) are not actuated.

- Provide for remote-manual operation of the system by an operator.

- Provide a high degree of assurance that the system operates when necessary.

- Have the power supply for the system from immediately available energy sources of high reliability.

- Provide for periodic testing during plant operation.

5.5.6.3 System Description

The RCIC system consists of a steam-driven turbine-pump unit and associated valves and piping capable of delivering makeup water to the RPV. The RCIC system is shown on drawing nos. H-26023 and H-26024.

The steam supply to the turbine comes from the reactor vessel. The steam exhaust from the turbine dumps to the suppression pool. The pump can take suction from the demineralized water in the condensate storage tank (CST) or from the suppression pool.

The equipment and the operations required by the operator for all manual operations of the RCIC are as follows:

A. Manual startup: Start up the gland-condensing equipment. Line up the RCIC pump discharge either to the reactor or to the CST by respectively opening either the reactor injection or storage tank injection valve after first verifying that the other is closed. Verify that the suction line valves are open initially to the storage tank. Depress the RCIC manual initiation push button; then verify the opening of the steam supply valve (2E51-F045).

B. Manual shutdown: Push the turbine trip while closing the steam supply valve to the turbine. Close the pump discharge valve used. Turn off the gland-condensing equipment.

The pump discharges either to the feedwater line or to a full-flow return test line to the CST. A minimum-flow bypass line to the suppression pool is provided to protect the pump during startup and shutdown. The makeup water is delivered into the RPV through the feedwater line and is distributed within the reactor vessel through the feedwater sparger. Cooling water for the RCIC turbine lube oil cooler and barometric condenser is supplied from the discharge of the pump, as shown on drawing nos. H-26023 and H-26024.

Following any reactor shutdown, steam generation continues because of heat produced by the radioactive decay of fission products. Initially, the rate of steam generation can be as much as ~ 6% of rated flow and is augmented during the first few seconds by delayed neutrons and some of the residual energy stored in the fuel. Steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, to the suppression pool. The fluid removed from the RPV is normally made up by the feedwater pumps supplemented by leakage from the CRD system. If makeup water is required to supplement these primary sources of water, the RCIC turbine-pump unit starts automatically upon receipt of the RPV water level 2 signal (drawing no. H-24751) or is started by the operator from the MCR. The RCIC delivers its design flow within 45 s after actuation. To limit the amount of fluid leaving the RPV, the RPV water level 1 signal actuates the closure of the MSIVs.

The RCIC makeup capacity is sufficient to avoid the need for the low-pressure emergency core cooling system (ECCS). Pump suction is normally lined up to the CST. The volume of water stored for the RCIC is sufficient to allow operation for 8 h after shutdown, assuming that none of the steam generated in the RPV is returned to the RPV as condensate. Other systems that use the same reservoir and could jeopardize the availability of this quantity of water can be isolated. Should the CST be drawn down to a low level, an automatic transfer of pump suction to the suppression pool occurs.

The RCIC system is sized to prevent actuation of the RPV water level 1 signal for RPV isolation incidents. Prevention of this signal ensures core cooling and prevents automatic depressurization system (ADS) actuation, thus preventing inadvertent blowdown of the RPV for this situation.

Quantitative information on steam and delivery water conditions are given on drawing no. S-25171 for all operating modes of the RCIC system.

The backup supply of cooling water for the RCIC is the suppression pool. The turbine-pump assembly is located below the level of the CST and below the minimum water level in the suppression pool to ensure positive suction head to the pump. NPSH requirements are satisfied by providing adequate suction head and adequate suction line size. System performance under various operating conditions is shown on drawing no S-25171.

All components required for initiating the RCIC are completely independent of auxiliary ac power, plant service air, and external cooling water systems. These components require only power derived from the station battery to operate the valves and logic. The power source for the turbine-pump unit is the steam generated in the RPV by the decay heat in the core. The steam is piped directly to the turbine, and the turbine exhaust is piped to the suppression pool.

The starting sequence for the RCIC turbine involves the use of a steam admission valve having a special contour plug to reduce the severity of the turbine start transient. The contour plug is designed to limit steam flow into the turbine during the initial valve opening stroke, thereby limiting the high angular acceleration rate and the subsequent high turbine speed during the first few seconds of operation. This feature allows the turbine to be under governor valve control before the steam admission valve is opened fully.

An analysis of the consequences of a safe shutdown earthquake with a concurrent loss-of-offsite power (LOSP) was performed to demonstrate that the use of manual actions after 10 min to accomplish switchover of the RCIC to the suppression pool suction line is acceptable.

The analysis was made using the following assumptions:

- Reactor scram on RPV water level 3 at t = 0.
- Isolation (MSIV) shown on an LOSP.
- CST supply to RCIC system not available.
- High-pressure coolant injection (HPCI) system unavailable (worst single failure).
- No offsite power.
- RCIC suction taken from suppression pool at t = 10 min.

The results of this transient analysis show that with the RCIC system delivery at its normal 400 gal/min, from 10 min after the initiation of the event the reactor water level never gets lower than at least 1 1/2 ft above the top of the active fuel. It may be noted that this result is additionally conservative in that for most cases the water level would be ~ 2 ft higher than the scram level at t = 0. Also, the core may be uncovered by several feet at the top before fuel failure is anticipated. The SAFE 03 computer code (approved for appendix K analysis) was used for this evaluation.

The reference 5 report presents the results of a similar transient analysis. This analysis shows that RCIC can fulfill its design function with a 45-s system response time and the system flow reduced by 10% (from 400 gal/min to 360 gal/min).

If for any reason the RPV is isolated from the main condenser, pressure in the RPV increases but is limited by automatic or remote-manual actuation of the safety relief valves.

Throughout the period of RCIC operation, exhaust from the RCIC turbine is condensed in the suppression pool, which results in a slow temperature rise of ~ 3°F/h in the pool. If necessary, one RHR heat exchanger can be used to cool the suppression pool after ~ 1.5 h. If for any reason the RCIC is unable to supply sufficient flow for core cooling, the ECCS provides the required boundary protection. A further discussion of this is found in section 6.3.

The RCIC turbine-pump unit is located in a shielded area to ensure that personnel access areas are not restricted during RCIC operation. The steam supply valve and turbine controls provide for automatic shutdown of the RCIC turbine on receipt of the following signals:

- RPV water level 8: Indicates that core cooling requirements are satisfied.
- Turbine overspeed: Prevents damage to the turbine and turbine casing.

- Pump low suction pressure: Prevents damage to the turbine pump unit that results from loss of cooling water.

- Turbine high exhaust pressure: Indicates turbine or turbine control malfunction.

- System isolation signal: Indicates need to shut down equipment.

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

Because the steam supply line to the RCIC turbine is a primary containment boundary, certain signals automatically isolate this line and cause shutdown of the RCIC turbine.

The RCIC turbine has a speed governor that is positioned by the demand signal from the flow controller. The speed governor limits the turbine-pump speed to its maximum normal operating value and positions the turbine governor valve as required to maintain constant pump discharge flow over the pressure range of system operation. Maximum output from the controller corresponds to maximum turbine speed.

The RCIC system may provide the ability to mitigate the consequences of small pipe breaks, but it is not provided primarily for such purpose. The ECCS provides redundant protection for the entire spectrum of pipe breaks. For small breaks this protection would be provided by HPCI and automatic depressurization.

The RCIC system provides decay-heat removal capability when the main condenser is unavailable, i.e., isolated from the nuclear system, for heat sink purposes, but is not a subsystem of the ECCS.

Long-term heat removal capability may be provided by the RCIC during scram, pressure relief, core cooling, RPV isolation, and restoration to ac power. The RHR system may be used for long-term heat removal during any long-term isolation. These events are all situations in which the RPV is isolated from the main condenser. None of these events is a pipe break (loss-of-coolant) situation requiring immediate reactor water level restoration.

The HPCI and RCIC systems are located in separate rooms in different corners of the reactor building. Piping runs are separated and the water delivered from each system enters the RPV via different nozzles.

The RCIC system is designed to meet Seismic Category I requirements. Except for isolation the RCIC system is not designed to meet the environmental qualification requirements for harsh environments (Rulemaking 10 CFR 50.49). Details are provided in the Plant Hatch Central File. Environment in the equipment room is maintained by a separate auxiliary system.

RCIC system operation during a station blackout event is discussed in section 8.4.

5.5.6.4 Safety Evaluation

To ensure that the RCIC operates when necessary and in time to provide adequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. Evaluation of reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system.

The RCIC system components within the drywell, up to and including the outer isolation valve, are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 1. See subsection 7.3.2 for a discussion of the isolation signals for the RPV and primary containment isolation system. See subsection 7.4.1 for a discussion of the RCIC system instrumentation and control logic.

The RCIC system is normally lined up with the pump taking suction on the CST. All valves between the storage tank and the first isolation valve on the pump discharge line are open. This allows communication between the CST and the discharge line, through the RCIC pump. The minimum water level in the CST is at el 137 ft, the RCIC pump suction connection to the tank is at el 130 ft 6 in., and the elevation of the first isolation valve in the discharge line is 123 ft 0 in. No portion of the RCIC pump suction or discharge lines is higher in elevation than the suction connection on the storage tank. Therefore, the 14-ft el difference between the water level in the storage tank and the first isolation valve ensures that the discharge line remains completely filled with water up to the isolation valve.

The discharge line connects to the bottom of the feedwater line at el 140 ft 0 in. Therefore, the remainder of the discharge line is maintained full by feedwater flow.

A vacuum breaker system is installed close to the RCIC turbine exhaust line torus penetration to avoid siphoning water from the torus into the exhaust line, as steam in the line condenses during and after turbine operation. The vacuum breaker line runs from the torus air volume to the RCIC exhaust line through two normally open motor-operated gate valves and two swing check valves arranged to allow airflow into the exhaust line and preclude steam flow to the torus air volume.

During turbine operation, condensate buildup in the turbine exhaust line is minimized by the installation of a drain pot in a low point of the line near the turbine exhaust connection. The condensate collected in the drain pot drains to the barometric condenser through a steam trap.

The above described design features and operating procedures preclude water hammer effects at the pump discharge or turbine exhaust.

The most limiting operating condition for the RCIC pump is when taking a suction from the suppression pool. The NPSH margin for this condition is 16.2 ft.

5.5.6.5 Tests and Inspections

A design flow functional test of the RCIC system is performed during plant operation by taking a suction from the CST and discharging through the full-flow test return line back to the CST. The discharge valve to the feedwater line remains closed during the test, and reactor operation is undisturbed. Control of the pump discharge valve is obtained by first closing the upstream discharge valve. Control system design provides automatic return from the test to the operating mode when system operation is required during testing of individual components. Periodic inspections and maintenance of the turbine-pump unit are conducted in accordance with the manufacturer's instructions. Valve position indicators and instrumentation alarms are displayed in the MCR.

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

5.5.7 RHR SYSTEM

5.5.7.1 Safety Design Basis

The RHR system is designed:

- In the LPCI mode to act automatically, in combination with other ECCS systems, to restore and maintain the coolant inventory in the RPV so that the core is adequately cooled to preclude fuel-cladding perforation and subsequent energy release due to a metal-water reaction.

- In the containment spray mode to remove airborne particulates in the drywell and to reduce the temperature and pressure of the primary containment atmosphere post-LOCA. Crediting this function was added as part of the implementation of an alternative source term (AST)(reference subsection 15.1.11).

- In conjunction with other ECCS systems, to such diversity and redundancy that only a highly improbable combination of events could result in its inability to provide adequate core cooling.

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

- To provide a high degree of assurance that the RHR system operates satisfactorily during a LOCA and that each active component is capable of being tested during operation of the nuclear system.

- To satisfy Seismic Category I requirements.

- To satisfy applicable environmental qualification requirements. (Refer to Plant Hatch Central File.)

- So that the residual heat removal service water (RHRSW) can be pumped directly into the RHR system.

- To provide heat exchangers with a heat removal capability for long-term containment cooling.

5.5.7.2 Power Generation Design Bases

The RHR system is designed:

- To have enough heat removal capacity to cool down the reactor to 125°F within 20 h after shutdown.

- To have fuel pool connections so that the RHR heat exchangers can be used to supplement the fuel pool cooling capacity.

- So that closed loop flowpath between the suppression pool and the RHR heat exchangers can be established so that the heat removal capability of these heat exchangers can be used to cool the suppression pool.

5.5.7.3 System Description

5.5.7.3.1 Summary

The RHR system is designed for six modes of operation to satisfy all the objectives and bases. The modes are summarized as follows:

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

The major equipment of the RHR system consists of two heat exchangers and four RHR pumps. The RHRSW system (subsection 9.2.7) provides cooling water to the heat exchangers. The equipment is connected by associated valves and piping, while controls and instrumentation are provided for proper system operation. The RHR system is shown on drawing nos. H-26014 and H-26015. The RHR system process flow diagram is shown on drawing nos. S-25140 and S-25141. A description of how operation of the equipment in the RHR system in conjunction with other subsystems of the ECCS protects the core in case of a LOCA is presented in section 6.3.

The RHR pumps are sized for the flow required during LPCI operation, which is the subsystem that requires the maximum flowrate. Paragraph 6.3.2.2.4 contains a discussion of the LPCI system. The pumps are arranged and located so that adequate suction head is ensured for all operating conditions. The pump motor is air cooled.

The heat exchangers are sized on the basis of their required duty for the shutdown cooling function. The heat exchanger shell and tube sides are provided with drain connections. The shell side is provided with a vent to remove noncondensable gases. Relief valves on the heat exchanger shell inlets and a relief valve on the HPCI steam supply line to the RHR heat exchangers protect the heat exchangers from overpressure.

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

The RHR heat exchangers' duties for the principal modes of operation are shown on drawing no. S-25140.

The most limiting duty is associated with cooling the reactor to 125°F in the normal shutdown cooling mode. The performance of this type of heat exchanger operating in the normal shutdown cooling mode (water to water) is well established in currently operating BWR facilities.

Classification information for the RHR heat exchangers is presented in table 3.2-1.

The RHR system can be connected to the fuel pool cooling and cleanup system (FPCCS), as shown on drawing nos. H-26014 and H-26015, so that the RHR heat exchangers can assist fuel pool cooling during high heat-load conditions. Subsection 9.1.3 contains a description of the FPCCS.

One loop, consisting of a heat exchanger, two RHR pumps in parallel, and associated piping, is located in one area of the reactor building. The remaining heat exchanger, pumps, and piping, all of which form a second loop, are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system.

A jockey pump system is provided to preclude water hammer effects (paragraph 6.3.2.2.5).

A suppression pool temperature monitoring system provides a measure of the torus atmosphere and the torus water temperatures during both normal and abnormal plant conditions. The suppression pool temperature monitoring system is required to ensure the suppression pool is within the allowable limits set forth in the plant Technical Specifications. The numbers and distribution of the pool temperature sensors are shown in figure 5.5-12. The sensors can be grouped into two categories:

1. Eleven "high" sensors (T48-N301A through N303A, N304B, N305A through N311A) located ~ 1/2 ft below the normal suppression water surface.

2. Four "low" sensors (T48-N009A-D) located ~ 10 ft below the normal suppression pool water surface.

Both groups of sensors are shown on figure 5.5-12. The T48-N301B through N303B, N304A, N305B through N311B sensors are installed spares.

Bulk suppression pool temperature is taken as the average of the group 1 average and group 2 average. This average is manually calculated from readouts available in the MCR. This calculated bulk suppression pool temperature is used for routine Technical Specification surveillance.

The group 1 sensors are not required to be operable per the plant's Technical Specifications; they only input visual alarms. They are all fed from the same (division 1) power supply; nevertheless, they are available for use during routine plant operation.

The group 2 sensors are the original suppression pool water temperature sensors. These sensors input audible alarms, and are fed from redundant power supplies. Should more than

two of the group 1 sensors be determined inoperable when the suppression chamber is required, a preplanned alternate method of determining average temperature may be used. The table below illustrates the correction factor (if any) to be added to the operable group 2 elements. These correction factors were developed from a detailed review of Plant Hatch suppression pool temperature data.

Plant Condition (See Notes)		Correction Factor (°F) to Operable Group 2 Elements
(a)	Normal operation; torus cooling not operating (Note 1); no HPCI testing (Note 2); no leaking SRV(s) (Note 3)	5
(b)	Normal operation; with or without torus cooling operating; HPCI testing; with or without leaking SRV(s)	(Note 4)
(c)	Normal operation; torus cooling operating; no HPCI testing; with or without leaking SRV(s)	0

<u>NOTES</u>:

1. Torus cooling is at least one loop of RHR in pool cooling or torus spray mode.

2. The Technical Specifications limit for this condition is 105°F.

3. A leaking SRV is defined as an SRV experiencing significant steam leakage past the seat. All the steam is not condensed in the SRV discharge line, thus resulting in steam expulsion into the pool.

4. Without group 1 temperature indication, HPCI testing time should be limited to assure the bulk pool temperature does not exceed 105°F. Pool temperature data should still be recorded each 5 min as instructed by the Technical Specifications, but the run time should be administratively controlled by the following:

   Maximum run time in minutes = (105 - T initial) x 2

   where:

   T initial is the pool temperature taken prior to the test with torus cooling operating. This equation assumes a 30°F/h rise in bulk pool temperature.

With the exception of the lack of an audible alarm from the group 1 sensors, the plant's bulk suppression pool temperature monitoring system meets the requirements of NUREG-0661. The

lack of an audible alarm from the group 1 sensors is acceptable because suppression pool temperature is monitored daily during normal plant operation and at 5-min intervals during periods of heat addition to the pool. The group 1 sensors also input a visual MCR alarm, and an audible alarm comes from the group 2 sensors.

The suppression pool temperature monitoring system has no control functions but provides the operator with temperature data during normal and abnormal plant conditions.

5.5.7.3.2 Shutdown Cooling Mode

The shutdown cooling mode is an integral part of the RHR system. It is operated during normal shutdown and cooldown. The initial phase of nuclear system cooldown is accomplished by dumping steam from the RPV to the main condenser. When the nuclear system temperature has decreased to where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, the vacuum in the main condenser cannot be maintained and the RHR system is placed in the shutdown cooling edge of operation. The shutdown cooling system is able to complete cooldown to 125°F within 20 h after the control rods have been inserted and can maintain the nuclear system at 125°F for reactor refueling and servicing.

Reactor coolant is pumped from one of the RRS loops by one or both of the RHR pumps in the loop and is discharged through the RHR heat exchangers where cooling occurs by heat being transferred to the RHRSW. Reactor coolant can be returned to the RPV through RRS loops. After the decay heat levels have subsided, the entire shutdown cooling load can be shifted to one residual heat exchanger, leaving the other available for other cooling loads.

The RHR system is normally inactive; therefore, the water between valves F050 and F015 is stagnant and, thus, at ambient conditions, ~ 135°F. For this water to flash into steam when the reactor vessel is being depressurized, the temperature of the water between F050 and F015 must be raised to at least 327°F. This temperature corresponds to a pressure of ~ 85 psi. The RHR system is initiated when the vessel pressure drops from ~ 135 psi to 85 psi so that 327°F is the lowest temperature at which the water would have to be.

The only source of heat that could cause the water to increase in temperature is the hot water, 546°F, in the reactor recirculation lines. This heat can be conducted only through the water and piping in the RHR system from where it interties with the recirculation system since the pipe run is dead ended against F050. This pipe run is ~ 22-ft long, and the results of a heat transfer calculation indicate that the temperature of the water between F050 and F015 cannot increase. At a distance of ~ 13 ft from the point where the RHR system and the RRS intertie, the heat losses due to convection from the pipeline are equal to the heat being transferred through the line by conduction. The temperature of the line is at ambient conditions.

Due to the above, it is not believed that there is flashing between F050 and F015, and therefore water hammer is not a problem.

5.5.7.3.3 Suppression Pool Cooling/Containment Spray Modes

During reactor operation, suppression pool cooling limits the temperature of the water in the suppression pool so that, immediately after the design basis LOCA, pool temperature does not exceed 170°F. The subsystem also limits the long-term post-accident peak temperature of the pool to < 212°F. Tests show that at 170°F, complete condensation of blowdown steam from the design basis LOCA can be expected. Although complete condensation is expected at higher suppression pool temperatures, no test data are available for any higher temperature.

The containment spray mode is an integral part of the RHR system. The containment spray mode can be manually initiated after the LPCI cooling requirements have been satisfied. The containment spray mode provides containment cooling for post-accident conditions and removes airborne particulates in the drywell post-LOCA. Water pumped from the suppression pool through the RHR heat exchangers, where it is cooled by the RHRSW system, is diverted to spray headers in the drywell and above the suppression pool. For the containment spray mode of operation, the shell-side inlet temperature is the maximum suppression pool temperature expected at post-accident conditions. The spray in the drywell condenses any steam that may exist in the drywell, thereby lowering containment pressure. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent lines. The water then overflows to the suppression pool. Approximately 5% of this flow can be directed to the suppression chamber spray ring to cool any noncondensable gases collected in the free volume above the suppression pool.

The containment spray mode of the RHR system normally cannot be operated unless the core flooding requirements of the LPCI subsystem have been satisfied. The operator can bypass these requirements by using a keylock switch.

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

The equipment purchase specifications for the RHR heat exchangers which are used for the containment cooling and suppression pool cooling modes specify fouling factors. These fouling factors are a function of the nature of the fluids, the temperatures involved, and the fluid velocities. The basis for the fouling factor used in relation to the RHR heat exchangers is obtained from TEMA table T-2.41. This table recommends that a fouling factor of 0.002 be used for river water where the water velocity is > 3 ft/s and the water temperature is ≤ 125°F. HNP-2 uses river water with an outlet temperature of 118.6°F and a water velocity in the tubes of 9.8 ft/s. Thus, a fouling factor of 0.002 was used for the tube side of these heat exchangers. The heat exchanger designer includes the fouling factors in calculating his overall thermal resistance and provides sufficient surface area to allow the required heat transfer rate while in the fouled condition. The heat exchanger performance data sheets supplied by the heat exchanger designer/manufacturer show the expected (designed) performance of the heat exchanger under fouled conditions.

5.5.7.3.4 LPCI Mode

The LPCI mode is an integral part of the RHR system. It operates to restore and, if necessary, maintain the coolant inventory in the RPV after a LOCA so that the core is adequately cooled to preclude fuel-clad melting and subsequent energy release due to a metal-water reaction. The LPCI operates in conjunction with the HPCI system, the ADS, and the CS system. A discussion of the requirements and response of the LPCI for LOCA is included in paragraph 6.3.2.2.4.

LPCI is a low-head, high-flow function that delivers its rated flow to the RPV through the RRS loops. It is designed to reflood the RPV to at least two-thirds core height and to maintain this level. After the core has been flooded to this height, the capacity of one RHR pump is sufficient to make up for shroud leakage and boiloff.

The HPCI is a high-head, low-flow system that can pump water into the RPV when the NSSS is at high pressure. If the HPCI fails to deliver the required flow of cooling water to the RPV, the automatic depressurization feature of the overpressurization protection system described in subsection 5.2.2 functions to reduce nuclear system pressure, thus, enabling the LPCI and CS to automatically inject water into the RPV. The HPCI turbine is manually shut down after both CS and LPCI are in operation.

During LPCI operation, the RHR pumps take suction from the suppression pool and discharge to the RPV into the core region through the RRS loops. Any spillage through a break in the lines within the primary containment returns to the suppression pool through the pressure suppression vent lines. A minimum-flow bypass line to the suppression pool is provided so that the RHR pumps are not damaged if operating with the discharge valves shut.

RHRSW flow to the RHR heat exchangers is not required immediately after a LOCA because heat rejection from the containment is not necessary during the time it takes to flood the reactor. Power for the RHR and RHRSW pumps normally comes from an auxiliary ac power, but if offsite power is lost, power is made available from the standby ac power source.
To provide a source of water if any post-accident flooding of the primary containment is required, a crosstie exists from the piping on the discharge side of a pair of RHRSW pumps to the discharge piping on the shell side of an RHR heat exchanger. This connection is provided with redundant valving appropriate to a primary containment penetration. The valves are remotely operable from the MCR. The pair of RHRSW pumps that provide this function can add water to either RRS loop through the cross-connection between the piping of each RHR loop.

5.5.7.4 Safety Evaluation

Because the LPCI and containment cooling modes act in conjunction with other subsystems of the ECCS to satisfy the safety objective, they are evaluated in conjunction with the other subsystems of the ECCS in sections 6.2 and 6.3. The evaluation of the controls and instrumentation of the LPCI system is contained in subsection 7.3.1.

An interlock exists in the logic for the RHR shutdown cooling suction valves, which are normally closed during power operation, to prevent opening of the valves above a preset pressure setpoint (table 7.3-9 and drawing no. H-24732). This setpoint is selected to ensure pressure

integrity of the RHR system is maintained. Administrative operating procedures require the operator to close these shutdown cooling valves prior to pressure operation. However, as a backup, the interlock automatically closes these valves when the pressure setpoint is reached. Double indicating lights are provided in the for valve-position indication.

The RHR pump piping, controls, and instrumentation are separated and protected so that any single physical event or missile cannot make both RHR loops inoperable.

The RHR system piping cannot be overpressurized from a single failure for the following reasons:

A. The suction piping may not be connected to the recirculation piping until the pressure has decayed to 145 psig (allowable value). Also, the suction piping outside the suppression pool piping is classed as 300-lb rated.

B. The discharge piping is not overpressurized whenever the LPCI injection valve is open because a check valve between the system and the vessel blocks pressure. Leakage past the closed check valve is accommodated by relief valves F025A and B and F055A and B. In addition, the injection valve may not be opened for testing unless the upstream valve, rated for full pressure, is also closed.

C. The heat exchanger and its piping are protected against failure of the steam pressure control valves by relief valves F055A and B.

Impaired post-LOCA RHR system performance due to broken or loose parts in the suppression pool is avoided by providing the suction strainers above the suppression pool bottom, thereby minimizing the accumulation of debris on the screen. The strainer mesh is such that any particles allowed to pass through the strainer are not of sufficient size to block critical flow passage in the pumps. Additionally, debris passing through the strainer does not cause any blockage of small system flow openings. However, some small quantities of particulate matters which pass through the strainers may accumulate in cracks and crevices throughout the system. This small particulate matter does not cause flow stoppage in the pumps or heat exchangers.

The most limiting condition for RHR pump operation occurs during long-term post-LOCA containment cooling when the suppression pool reaches the peak temperature of 207.4°F. The NPSH margin under these conditions is discussed in paragraph 6.3.3.9.

5.5.7.5 <u>Tests and Inspections</u>

A design flow functional test of the RHR pumps is performed for each pair of pumps during normal plant operation by taking suction from the suppression pool. The discharge valves to the RRS loops remain closed during this test, and reactor operation is undisturbed.
An operational test of the discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested, thereby establishing the RCPB at the downstream valve, and then operating the upstream valve. The discharge valves to the containment spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All these valves can be actuated from the MCR by using remote-manual switches. Control system

design provides automatic return from the test to the operating mode if LPCI initiation is required during testing.

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

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

A discussion of the availability of the engineered safety features (ESFs) and frequency of testing of equipment is presented in subsection 6.2.2.

Preoperational tests were conducted during the final stages of plant construction prior to initial startup. These tests ensured correct functioning of all controls, instrumentation, pumps, piping, and valves. System reference characteristics such as pressure differentials and flowrates are documented during the preoperational testing and are used as base points for measurements obtained in subsequent operational tests.

For the containment spray mode, preoperational tests confirm that the containment spray headers and piping are clear of obstructions and the spray nozzles are capable of delivering rated flow. Air is injected into the drywell spray header via the blind flange connection on the outside of the primary containment. Unrestricted flow is verified through each spray nozzle. The spray nozzles in the suppression pool are checked with water during the suppression pool cooling tests.

For the suppression pool cooling mode, the preoperational tests verify that the RHR heat exchanger shell-side design flowrate can be obtained while circulating water from the suppression pool. During the test, head-versus-flow curves are developed for reference in evaluating the future performance of the suppression pool cooling mode, RHR pumps, and restricting orifices fitted to the pump discharge lines to prevent RHR pump runout.

An analysis has been performed for HNP-2 to determine the potential for RHR/LPCI pump runout, post-design basis LOCA. From the standpoint of maximizing LPCI pump flow following a LOCA, the most limiting configuration has been quantitatively determined, by comparison of overall system resistance, to be the case where only one LPCI pump is operating into the broken recirculation loop. Also, the break is conservatively assumed to be at the LPCI connection to the recirculation piping so that no credit is taken for flow resistance of the recirculation system.

The system resistance was calculated by assigning equivalent lengths of straight-pipe values to the various fittings and valves as given in Crane Company Technical Paper 410 and by extracting the lengths of piping runs from the physical piping drawings.

The pressure drop per equivalent 100 ft is expressed by:

$$\Delta P/100 = \frac{0.000336fVM^2}{D^5}$$

where:

f = friction factor

V = specific volume of the fluid

M = mass flowrate

D = pipe inside diameter

The specific pressure drop in interest is that which occurs at a flowrate of 11,100 gal/min which is the maximum allowable flowrate per pump. The existing system head loss at 11,100 gal/min for one LPCI pump operating into the broken loop was found to be ~ 80 ft of water, using the above equation.

The pump vendor's certified performance curve was then consulted to find the pump total dynamic head at the maximum allowable flowrate of 11,100 gal/min. This was found to be ~ 290 ft of water.

Therefore, for the system curve to match the pump total dynamic head at the point of interest, 11,100 gal/min, an additional 210 ft of water, i.e., 290 to 80, pressure drop must be added to the system by the restricting orifice.

Since the amount of downstream pressure recovery for an inline restricting orifice is a function of the orifice beta ratio (orifice bore diameter to pipe inside diameter), the orifice bore required to give the desired system head loss, after pressure recovery, is found by using a convergence procedure with the pressure drop measured across the orifice as the trial argument and using the formula for liquid flow through nozzles and orifices from Crane Company Technical Paper 410. This procedure resulted in an orifice bore diameter of 7.56 in.

A description of the RHR/LPCI system preoperational testing is provided in supplement 14A, section 14A.22.

During plant operation, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be inspected visually at any time. Components inside the primary containment can be inspected when the drywell is open for access. Testing frequencies are correlated with testing frequencies of the associated controls, and instrumentation is tested by the same action. When a system is tested, operation of the components is indicated by installed instrumentation.

The RHR relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments.

5.5.8 RWC SYSTEM

5.5.8.1 Design Basis

The principal function of the RWC system is to provide a means for reducing the concentration of radioactive and corrosive materials in the RCS.

The RWC system is designed to:

- Discharge excess reactor water during startup, shutdown, and hot standby conditions.
- Minimize reactor heat loss during system operation.
- Remove solid and dissolved impurities from recirculated reactor coolant.
- Minimize temperature gradients in the RRS piping and vessel during periods of low flowrates.

5.5.8.2 System Description

The RWC system, shown on drawing nos. H-26036 and H-26037, continuously purifies the reactor water. The system continuously removes water from the suction line of each RRS pump and from the reactor bottom head. The processed water is returned to the NSSS or to storage.

A regenerative heat exchanger is provided to limit the loss of heat from the nuclear system. The RWC system can be operated at any time during planned operations, or it may be shut down when not required to clean up or remove reactor coolant.
The major equipment of the RWC system is located in the reactor building. This equipment includes pumps, regenerative and nonregenerative heat exchangers, and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping while controls and instrumentation are provided for proper system operation. Design data for the major pieces of equipment are presented in table 5.5-3.

Reactor water is cooled in the regenerative and nonregenerative heat exchangers, then filtered, demineralized, and returned to the reactor feedwater system through the shell side of the regenerative heat exchanger. A process flow diagram of the RWC system is shown on drawing no. S-25285.

Because the maximum temperature of the filter-demineralizer units is limited by the ion-exchange resin operating temperatures (table 5.5-3), the reactor coolant must be cooled before being processed in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the influent water to the effluent water. The effluent returns to the feedwater system. The nonregenerative heat exchanger cools the influent water further by transferring heat to the reactor building closed cooling water system. The nonregenerative heat exchanger is designed

to maintain the required filter-demineralizer operating temperature, even when the effectiveness of the regenerative heat exchanger is reduced by diversion of excess reactor water from the filter-demineralizer effluent to either the main condenser (normal discharge) or to the radwaste system. The flow is then returned to storage instead of returning to the reactor through the regenerative heat exchanger.

The filter-demineralizer units, shown on drawing no. H-26037, are pressure-precoat-type filters using only ground, powdered ion-exchange resins as a filter and ion-exchange medium. Spent resins are not regenerable and are backwashed from a filter-demineralizer unit to a resin receiver tank from which they are transferred to the radwaste system for processing and disposal. When the system is being returned to service, slow pressurization of a filter-demineralizer unit is manually executed through a bypass line around the inlet air-operated valves.

The suction line of the RCPB portion of the RWC system contains two motor-operated isolation valves which automatically close in response to signals from the RCPB leak-detection system (LDS). This action prevents the loss of reactor coolant and the release of radioactive material from the reactor. Subsections 5.2.7 and 7.6.9 and table 5.2-6 describe the RCPB LDS.

The outermost isolation valve also automatically closes to prevent removal of liquid poison in the event of standby liquid control system (SLCS) actuation and to prevent damage of the filter-demineralizer resins if the outlet temperature of the nonregenerative heat exchanger is high. These isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing.

A remote manually operated gate valve on the return line to the reactor provides long-term backup isolation of the system for the reactor. Instantaneous reverse-flow isolation is provided by check valves in the RWC return line, as shown on drawing no. H-26036.

5.5.8.3 <u>Safety Evaluation</u>

To prevent resins from entering the RRS in the event of failure of a filter-demineralizer resin support, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer has an alarm that is energized by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units when necessary. Relief valves and instrumentation are provided to protect the equipment against overpressurization and the resins against overheating. The system is automatically isolated for the reasons indicated when signaled by any of the following occurrences:

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

- RPV water level 2 to protect the core in case of a possible break in the RWC system piping and equipment.

- SLCS actuation to prevent removal of the boron by the filter-demineralizers.

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided in the influent header and effluent line of each filter-demineralizer unit for continuous indication and recording of system conductivity. High conductivity is annunciated in the MCR. The influent sample point is also used as the normal source of reactor coolant samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

Operation of the RWC system is controlled from the MCR. Resin-changing operations, which include backwashing and precoating, are controlled from a local control panel in the reactor building. Drawing nos. H-24758 and H-24759 show the functional control diagram.

5.5.8.4 Tests and Inspections

Because the RWC system is usually in service during plant operation, satisfactory performance is demonstrated without the need for any special tests and inspections beyond those specified in the manufacturer's instructions.

5.5.9 MAIN STEAM LINES AND FEEDWATER PIPING

5.5.9.1 Design Bases

The main steam lines are designed, as described in section 10.3, Main Steam Supply System, to conduct steam from the reactor vessel to the various components over the full range of reactor power operation. Additional design information concerning the main steam piping is found in sections 3.6, 3.9, 5.2, and 10.3.

The feedwater piping is designed to supply feedwater to the reactor over the full reactor power range and to accommodate all anticipated operational stresses without failure. Additional design information concerning the feedwater piping is found in sections 3.6, 3.9, and 5.2, and subsection 10.4.7.

5.5.9.2 Description

Information describing the main steam piping is found in sections 3.6, 3.9, 5.2, and 10.3.

Design information describing the feedwater piping is found in sections 3.6, 3.9, and 5.2, and subsection 10.4.7.

5.5.9.3 Safety Evaluation

An evaluation of the main steam piping is found in sections 5.2 and 10.3.

An evaluation of the feedwater system piping is found in section 5.2 and subsection 10.4.7.

5.5.9.4 Tests and Inspections

Tests and inspections of the main steam and feedwater piping are conducted as defined in subsections 10.3.4 and 10.4.7.

5.5.10 PRESSURIZER

This subsection is not applicable to BWRs.

5.5.11 PRESSURIZER RELIEF TANK

This subsection is not applicable to BWRs.

5.5.12 VALVES

5.5.12.1 Design Bases

Valves are components of the system pressure boundary having moving parts and are designed to operate efficiently to maintain the integrity of this boundary.

Line valves, such as gate valves, globe valves, and check valves are located in the various fluid systems to perform a mechanical function, and to allow either operator control or automatic control of the various fluid processes.
The valves are designed to operate under the internal pressure/temperature loading as well as the external loading anticipated during the various system transient and steady-state operating conditions.

5.5.12.2 Description

Line valves furnished are standard types, designed and constructed in accordance with the requirements of the applicable code. Valve design codes are delineated in subsection 3.2.2.

All materials, exclusive of seals and packing, have been selected to endure the 40-year plant life under the environmental conditions applicable to the particular system. Aging management programs (subsections 18.2.1 and 18.2.9) monitor the ongoing condition of the valves so that actions are taken to provide reasonable assurance that these components are capable of performing their intended functions for 40 years and beyond. Section 3.11 provides the environmental conditions to which all valves required to function to effect a safety action have been designed.

Valve operators are selected to provide operability under the most severe conditions applicable to the particular system.

5.5.12.3 Safety Evaluation

Line valves are either shop tested, prototype tested, or analyzed to perform at the service conditions/accident conditions specified by the purchase specification. Pressure-retaining parts are selected as required by the applicable code.

To minimize leakage past seating surfaces, maximum allowable leakage rates are specified for both back seat and main seat for gate and globe valves.

5.5.12.4 Tests and Inspections

Valves serving as containment isolation valves, and which must remain closed or open during normal plant operation, can be partially exercised during plant operation to ensure their operability.

Valves serving as system-block or throttling valves may be fully exercised without jeopardizing system integrity.

Leakage from valve stems is monitored as described in subsection 9.3.3.

5.5.12.5 Motor-Operated Valves Performance Testing

Table 5.5-4 lists seismic and environmental tests performed on Limitorque motor operators which are used exclusively on HNP-2 for motor-operated valves provided by Bechtel. Although many of these tests were conducted after most of the HNP-2 motor operators were purchased, the results were still valid for previously purchased valves.

In addition to these tests, Limitorque tests the performance of each motor operator independently of the valve for proper torque settings. The valve operator assembly is subsequently tested by the valve manufacturer for compliance with the design specification. Bechtel inspection randomly witnessed tests for opening and closing times and proper calibration of position indicators. Each Quality Assurance (QA) documentation package was reviewed by Bechtel inspection prior to release of the valve.

Limitorque's current QA program was approved by the Nuclear Regulatory Commission (NRC) on docket 999-001-00 for program number 44070.

Motor-operated valve performance testing conducted by Georgia Power Company (GPC) includes testing during Construction Assurance Testing Program, the preoperational test phase, and throughout the operating life of the plant by the surveillance testing program.

During the Construction Assurance Testing Phase, extensive testing and documentation of valve performance data was accomplished with the GPC Motor-Operated Valve Data Sheet which includes nameplate data, test data, limit switch setting, torque switch setting, and operating data. The test data section includes 18 different tests:

- *Rotation check.*
- *Lubrication.*
- *Packing adjustment.*
- *Verification of proper packing type.*
- *Packing size check.*
- *Cable termination check.*
- *Controls operability check.*
- *Ground connection check.*
- *Bonnet check.*
- *Cable megger or hi pot.*
- *Motor megger or hi pot.*
- *Alarm operability.*
- *Indicating lights check.*
- *Proper size fuses installed.*
- *Thermal overload installed.*
- *Thermal overload size check.*
- *Stem protector installed.*
- *Stem cleaned and lubricated.*

The Construction Assurance Tests program provided a means to determine that systems and equipment are correctly installed and free from defects, missing components, errors in installation, etc.

During the preoperational test program, motor-operated valves were included in the overall systems preoperational test to the extent that the valves proper operation during all modes of system operation is verified. The purpose of the preoperational test program was three-fold:

- *To confirm that construction was complete to the extent that equipment and systems can be put into use during completion of other construction.*

- *To adjust and calibrate the equipment to the extent possible in the "cold" plant condition.*

- *To assure that all process and safety equipment was operational and in compliance with license requirements to the extent necessary to proceed into initial fuel loading and the startup test program.*

The foregoing was achieved in accordance with the Final Safety Analysis Report, by formal written preoperational tests on systems related to nuclear safety. Balance-of-plant systems were also tested with a written procedure, using the same format to assure that all plant equipment functions reliably.

The preoperational test performance period was an important phase in the training of operating personnel. Experience and understanding of plant systems and components was gained with a minimum of risk to equipment or personnel. This gave maximum opportunity to evaluate and train operating personne and to troubleshoot systems. In addition, equipment and systems were operated for a sufficient period of time to discover and correct any design, manufacturing, or installation errors, and to adjust and calibrate the equipment.

Throughout the operating life of the plant, motor-operated valves whose proper operation is required to meet the plant Technical Specifications are periodically tested to ensure that the performance of these valves is satisfactory. This testing is done as required in plant Technical Specifications through the plant surveillance program. Valve cycling is not possible in every case when surveillance is conducted while the plant is operating at power, but valve operation is carried out as a part of the surveillance action whenever conditions permit.

5.5.13 SAFETY AND RELIEF VALVES

Overpressurization protection in the form of safety relief valves is provided to systems and subsystems closely related to the RCS, such as:

- CS system.
- HPCI system.
- RCIC system.
- RHR system and its subsystems.
- SLCS.
- CRD system.
- RWC system.
- Reactor feedwater system.

The safety relief valves of the RCS are discussed in subsection 5.2.2.

5.5.13.1 Safety Design Bases

Piping systems that are normally isolated from the RCPB by at least two power-operated isolation valves are provided with safety relief valves or other overpressure protection mechanisms to protect the isolated piping from overpressurization due to thermal expansion of the enclosed fluid.

These valves are sized and designed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III.

5.5.13.2 Description

5.5.13.2.1 CS System Relief Valves

Each CS pump discharge line is equipped with a relief valve set at 500 psig and having a capacity of 100 gal/min. The CS system is not subject to any kind of energy input except pump motor energy when pumps are operating against closed valves.

5.5.13.2.2 HPCI System Relief Valves

The HPCI pump suction line is equipped with a relief valve with the setpoint set at 100 psig and the capacity specified as 20 gal/min.

The setpoint and capacity for the cooling water line relief valve are 100 psig and 177 gal/min, respectively.

The barometric condenser is equipped with a relief valve intended to protect against overpressure in the condenser. The valve setpoint is 15 psig, and the capacity is specified as 20 gal/min at 10% accumulation.

In addition, rupture discs on the exhaust line protect the turbine casing. The discs are set at 175 psig and have a capacity of 600,000 lb/h at 175 psig.

The HPCI system is not subject to any kind of energy input except the hydraulic oil pump motor and the motors for the gland-seal condenser vacuum and drain pumps.

5.5.13.2.3 RCIC System Relief Valves

The RCIC pump suction line is equipped with a relief valve set at 100 psig and having a specified capacity of 10 gal/min at 25% accumulation. This relief valve is intended to protect against overpressurization of the RCIC pump suction piping due to leakage from the main feedwater system.

The relief valve in the cooling water line to the gland-seal condenser is set at 100 psig and has a 75-gal/min capacity. The purpose of this valve is to protect the lube oil cooler and associated piping in the cooling water loop from overpressurization which could result from a failure of the pressure-control valve (F015).

The barometric condenser is equipped with a relief valve set at 15 psig and having a specified capacity of 20 gal/min at 10% accumulation. The purpose of the valve is to protect against overpressurization of the condenser.

Rupture discs on the steam turbine exhaust line protect the turbine casing. The discs are set at 150 psig and have a capacity is 45,000 lb/h at 150 psig.

The RCIC system is not subject to any kind of energy input except when the pumps operate with closed valves.

5.5.13.2.4 RHR System Relief Valves

Each RHR pump discharge line is equipped with a relief valve set at 400 psig and having a capacity of 50 gal/min.

An RHR discharge line to the RCIC pump suction is provided with a relief valve set at 85 psig and having a capacity of 362 gal/min.

5.5.13.2.5 SLCS Relief Valves

A relief valve is provided in the discharge line of each pump with the setpoint and capacity set at 1400 psig and 43 gal/min each.

5.5.13.2.6 CRD System Relief Valves

The CRD pump suction lines and the accumulator charging station on the hydraulic control units are equipped with relief valves. The setpoints and capacities are:

- Pump suction relief valves set at 100 psig with 10 gal/min capacity.
- Accumulator charging station relief valves set at 950 psig.

5.5.13.2.7 RWC System Relief Valves

Relief valves are installed on the shell side of the heat exchangers and on the line to the condenser.

The setpoint and capacity of the relief valve on the line to the condenser are 150 psig and 204 gal/min at 130°F, respectively.

The relief valve on the shell side of the nonregenerative heat exchangers is set at 150 psig with 29 gal/min at 105°F capacity.

The thermal expansion relief valve on the shell side of the regenerative heat exchangers is set at 1200 psig.

5.5.13.2.8 Feedwater System Relief Valves

The feedwater system is designed to the maximum pressure of the RCS up to and including the outermost isolation valve. Beyond the outermost isolation valve the system is designated as a nonsafety class. Details of the feedwater system are discussed in subsection 10.4.7.

5.5.13.3 Safety Evaluation

The assumptions made in the evaluation of the adequacy of the relief valves provided are conservative, and the setpoints and capacities of the valves are sufficiently conservative to protect the system and subsystem pipings and components from the effects of overpressurization.

Some of the conservative assumptions are:

A. Conservative isolation valve leakage values are used in sizing the relief valves.

B. The system is considered isolated with the pump(s) operating at shutoff conditions. A 100% energy conversion from the pump motor horsepower to heat is assumed, neglecting heat losses and mechanical work.

C. Jet impingement of steam from a nearby broken pipe is taken into account in sizing the relief valves. To be conservative, heating of the piping is assumed to be from the condensation of steam by the piping.

D. The piping subject to heating is assumed to be uninsulated.

E. Reaction force on the piping from relief valve operation is assumed to be $R = 2 \times P \times A$, where R is the reaction force, P is the pressure setting of the valve, and A is the area of the valve inlet.

5.5.14 COMPONENT SUPPORTS

Support elements are provided for those components beyond the RCPB which are in systems or subsystems closely allied with the RCS. These systems include reactor feedwater, RHR, RCIC, RWC, HPCI, and standby liquid control.

5.5.14.1 Design Bases

Support components on the RCS and subsystem piping are provided to ensure the pressure retaining capability of the piping system due to weight, thermal, seismic, and fluid dynamic loads. The support components on nuclear Class 1, 2, and 3 piping are designed in accordance with the applicable subsections of ASME Section III, including addenda, prior to the purchase order date. In addition, methods established in Appendix XVII and Appendix F of the 1974 ASME Code, Section III are adapted where possible. All hanger assemblies are in accordance with the requirements of the Steel Structures Painting Council Standard Practice, SSPC-SP-10, and the Manufacturers Standardization Society of the Valve and Fittings Industry Standard Practices, MSS-SP-58 and MSS-SP-69.

5.5.14.2 Description

The design parameters of rigid-type supports, variable or constant spring-type supports, and anchors or guides used on the reactor coolant piping are determined by piping stress analysis. Provision is made for spring-type supports for the initial deadweight loading due to hydrostatic testing of steam systems to prevent damage to this type of support. Welded attachments to Class 1 pipe are minimized but, where necessary, are analyzed as Class 1 components. Classes 2 and 3 attachments are designed to reduce local stresses and are analyzed for the stresses induced in the pipe. Manufacturer's standard hardware is utilized as much as possible, but where nonstandard components are necessary their adequacy is confirmed by analysis. Deflections as well as stresses are limited in the evaluation of support components. The reactor vessel pedestal design is discussed in subsection 3.8.3.

5.5.14.3 Safety Evaluation

All support components are capable of withstanding the cumulative loading produced by the worst combination of the events classified under each of the normal, upset, emergency, and faulted conditions if applicable.

As discussed in section 3.6, pipe-whip restraints are provided to ensure protection of the RCS and subsystems piping and supports from a postulated line break. Pipe-whip restraints not in contact with the pipe are designed in accordance with the American Institute of Steel Construction (AISC), Seventh Edition. Restraints serving as both whip restraints and pipe supports are designed in accordance with both ASME Section III and the AISC. The pipe rupture design condition is faulted and the restraints are designed for both the rupture loads and the operational loads.

All support components, including hydraulic shock suppressors, are designed to operate under the effects of a gamma radiation of 1×10^7 rads over a 40-year period.

5.5.14.4 Tests and Inspections

Paragraph 3.7.3.14 discusses the field surveillance for seismic supports, which, in addition, verifies installation of all other types of supports on the reactor coolant piping. Upon hot-startup operations, thermal growth is observed to confirm that spring-type hangers and shock suppressors function properly between hot and cold setting positions. Final adjustment capability is provided on all hanger or support types.

Fully assembled shock suppressors are shop tested to verify operational characteristics for compliance with the design requirements. The units are observed for proper piston rod velocities, poppet valve closure, bypass flow, and fluid containment integrity.

5.5.15 OTHER SYSTEMS WITH COMPONENTS WITHIN RCPB

The HPCI and CS systems penetrate the RCPB. These systems are described in section 6.3.

5.5.16 RECIRCULATION PUMP TRIP SYSTEM

5.5.16.1 Safety Design Bases

The recirculation pump trip (RPT) system is designed to:

- Mitigate the consequences of the end-of-cycle scram reactivity shortfall.
- Meet the single-failure criterion.
- Meet Seismic Category I, Safety Class 2 requirements.
- Comply with applicable codes, guides, and standards.

5.5.16.2 System Description

The RPT system is a subsystem of the RRS. The RPT function in the recirculation control system is to trip the recirculation pumps in response to a turbine-generator trip or load rejection. Scram/recirculation pump trip initiation by either turbine stop valve closure or turbine control valve fast closure initiates a scram and an RPT to prevent the core from exceeding the thermal-hydraulic safety limit during AOOs (section 15.2). The RPT system reduces the severity of the turbine generator trip and load rejection events by tripping the recirculation pumps early in the event. The rapid core flow reduction increases void content and thereby reduces reactivity in conjunction with the control rod scram.

The RPT system is designed to meet Seismic Category I, Safety Class 2 requirements. The system consists of turbine control and stop valve closure sensors, reactor power level sensors control logic storage monitors separate division logics, and four Class 1E, 5-kV, 250-MVA circuit

breakers. The close and trip circuitry for the breakers are individually fused. Light indicators for operating bypasses are provided in the MCR. These lights are continuously indicated when the sensor or division logic has been bypassed or deliberately rendered inoperative for testing or repair purposes. In addition, indicators and annunciators are provided in the MCR for system input trip signals, initiation signal at system level, the status of trip coils, and the mechanical position of the circuit breakers. The RPT system logic receives its power from the same power sources as the reactor protection system (RPS). The RPT breaker control receives its power from the main battery systems (A and B).

During normal operation, all the main power breakers in both loops (figure 5.5-8) are closed. Upon receipt of a trip signal from either the control valve fast closure or the turbine stop valve closure logics, all four breakers open within 135 ms after initiation of the breaker opening mechanism over a specified frequency range of 37 to 45 Hz, interrupting power to the recirculation pump motors (figure 5.5-9), and their tripped status is displayed by the annunciators in the MCR. The trip signals must be reset manually by the operator to allow restarting of the recirculation pumps.

The anticipated transient without scram (ATWS) RPT is described in paragraph 7.6.10.7.

5.5.16.3 Safety Evaluation

The RPT system is designed to meet Seismic Category I requirements and complies with the requirements of the following codes, guides, and standards:

- 10 CFR 50, Appendixes A and B.
- Regulatory Guides 1.47, 1.53, 1.62, and 1.75.
- Institute of Electrical and Electronics Engineers (IEEE) Standards 279, 308, 323, 338, 344, 379, 383, and 384.

The RPT system is designed to be operable over the 1 and 2 recirculation pump operating regions of the thermal power-core flow map when the reactor power exceeds a predetermined power level (~ 30% of rated full load).

The RPT system consists of two separate trip divisions, each having at least two separate trip channels, sensors, and associated equipment for each measured variable. The RPT system logic is designed to preclude the inadvertent trip of more than one pump, given a single component failure.

The RPT system is designed to meet the single-failure criterion so that any single-trip channel (sensor and associated equipment) or system component failure does not prevent the system from performing its intended safety function.

The RPT system is separated from other recirculation control systems to the extent that failure of any single component in those systems does not prevent the RPT system from performing its intended function.

The RPT initiating trip circuitry is provided by the RPS. Existing RPS inputs sense "Turbine Stop Valve Closure" or "Turbine Control Valve Fast Closure." These signals are processed through new logic (equal to the existing RPS design quality) which blocks tripping the circuit breakers unless turbine first-stage pressure is above 30% of rated load.

5.5.16.4 Tests and Inspections

Surveillance tests (functional and calibration) on the sensors and logics may be performed during plant operations. Bypass switches provided prevent tripping of the breakers during these tests. The test requirements are as specified in the Technical Specifications.

5.5.17 LOW-LOW SET RELIEF LOGIC SYSTEM

5.5.17.1 Design Bases

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

- Mitigate the effects of postulated thrust loads on the safety relief valve discharge lines (SRVDLs) and the effects of postulated high-frequency pressure loads on the torus shell caused by subsequent actuations of the SRVs during a small- or intermediate-break loss-of-coolant accident (LOCA).
- Extend the time between SRV subsequent actuations to allow the SRVDL water leg to return to original level after an actuation.
- Remain operable in event of loss of offsite power (LOSP).
- Perform its design function assuming the worst postulated single failure. (The failure modes effects analysis (FMEA) is provided in table 5.5-5.)
- Assure no single failure shall cause more than one LLS valve to stick open
- Be testable during normal plant operation.

5.5.17.2 System Description

The arrangement of the SRV systems with the LLS design for HNP-2 is shown in table 5.5-6. The LLS design involves four non-ADS SRVs. The LLS control logic operates the four valves through arming and actuation. The arming function requires concurrent signals of any SRV opening and a high reactor vessel pressure exceeding scram setpoint.

The LLS system consists of SRV open-close monitors, nuclear boiler pressure instrumentation, and a cabinet housing LLS logic relays, solenoid valves, and pneumatic supply. (Accumulators are part of the pneumatic supply.) The SRV open-close monitors are pressure switches. Redundant switches on each tailpipe indicate an SRV opening. The nuclear boiler pressure instrumentation provides pressure trips for the arming pressure permissive and the LLS setpoints. One transmitter and master trip unit provide the arming permissive trip. A slave trip unit and another transmitter/master trip unit provide the two-out-of-two logic for LLS opening and one-out-of-two for reclosing logic to the solenoid valves. The solenoid valves and the drywell pneumatic system are used to pneumatically operate the LLS valves. The LLS valves discharge into the suppression pool. An automatic opening of SRVs will also occur at setpoints distributed among 3 groups (table 5.5-6), by pressure switch relay contacts inserted into the LLS pilot solenoid valve circuit. (See paragraph 5.2.2.2.3 for other details.)

5.5.17.3 Safety Evaluation

The objective of this analysis is to demonstrate that the design is capable of mitigating the thrust loads on the SRVDLs and the high-frequency loads on the torus shell from subsequent SRV actuations during small- and intermediate-break LOCAs. This can be accomplished by extending the time between actuations to exceed the water leg clearing time and by limiting subsequent SRV actuations to LLS valves only. The LLS system precludes the untimely actuation of the ADS valves by controlling only the LLS valves.[4] The capability of allowing sufficient time between SRV actuations was demonstrated by an analysis.[4] The overall response of the RPV and, specifically, the response of the SRV system during actuations were evaluated using current BWR evaluation methods and assumptions which are in conformance with the plant design basis.

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

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

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

Assuming the worst-case single failure, the LLS logic in HNP-2 can extend the time between SRV actuations from < 3 s to 39 s. Therefore, the LLS can mitigate the thrust load and shell pressure load concern from subsequent SRV actuation during a small-break LOCA even with the worst-case single failure and early reactor isolation occurring concurrently.

The predicted system responses for the limiting events postulated for HNP-2 are shown in figures 5.5-10 and 5.5-11. They show that the system pressure increases sharply as soon as isolation is completed. The pressure rise causes all 11 SRVs to actuate and initiates the LLS system. Actuation of SRVs quickly depressurizes the reactor vessel and all non-LLS valves close at the respective pilot setpoints or at their mechanical backup electric trip unit's deadband

minimum (see paragraph 5.2.2.2.3). The LLS valves remain open until their LLS closing setpoints are reached. When the lowest LLS valve closes, the reactor pressure rises again and only that valve continues to cycle to control reactor pressure. The time between actuations is approximately 37 s for HNP-2. Figure 5.5-11 demonstrates the case in which two LLS valves become inoperative in the lowered setpoint relief mode. The remaining two LLS valves can turn the system pressure around before any non-LLS valves actuate at the pilot setpoints; thereafter, the lower operable LLS valve cycles to control reactor pressure. The time between actuations is ~ 39 s. The time is longer, because the two LLS valves take a longer time to depressurize the reactor and subsequent repressurization by decay heat is at a slower rate.

Low-low set design was evaluated at uprated power and vessel pressure[6, 8, 9]and for the SRV setpoint change.[7] The higher steam generation rate reduced slightly the time between actuations. Reference 7 supports continuous operation with one SRV out-of-service in the LLS mode. However, ample margin in the time between actuations assured the water level in the SRV discharge line returned to its normal level.

With or without the LLS logic, HPCI or RCIC provide adequate core cooling.[4] Although the steam loss per discharge is higher with the LLS valves, the integrated total steam losses are identical for a LLS valve and a non-LLS valve. Initiation of HPCI or RCIC compensates for the steam loss through the LLS valves and provides adequate core cooling.

The LLS design does not result in exceeding any event acceptance limit for any applicable events identified in chapter 15.[3,4] Although the scenario for some events, such as loss-of-feedwater flow and small-break LOCA, may be changed, the safety margin of the plant is not reduced.

5.5.17.4 Tests and Inspections

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

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

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

REFERENCES

1. "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors Main Steam Line Isolation Valves," APED-5458, General Electric Company, March 1968.

2. "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, General Electric Company, March 1968.

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

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

5. "Safety Evaluation for Relaxation of RCIC Performance Requirements for Plant Hatch 1 and 2," AES-41-0688, General Electric Company, July 1988.

6. "Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 and 2," NEDC-32405P, General Electric Company, December 1994.

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

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

9. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

TABLE 5.5-1 (SHEET 1 OF 2)

REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

<u>External Loops</u>	
Number of loops	2
Pump sizes (nominal outside diameter)	
Pump suction (in.)	28
Pump discharge (in.)	28
Discharge manifold (in.)	22
Recirculation inlet line (in.)	12
Design pressure (psig) design temperature (°F)	
Suction piping and valve up to and including pump suction nozzle	1250/575
Discharge gate valve	1525/575
Piping up to vessel	1450/575
Vessel bottom drain	1275/575
Pump	1500/575
<u>Operation at Rated Conditions</u>	
RRS pump (each)	
Flow (gal/min)	45,200
Flow (lb/h)	17.1×10^6
Total developed head (ft)	530
Suction pressure (static) (psia)	1065
Required NPSH	
10% flow cold (ft)	70
Rated hot (ft)	350
Water temperature (max) (°F)	540
Pump brake hp (min)	5260
Flow velocity at pump suction (approximate) (ft/s)	28.3
Pump Motor	
Rating (V)	4160
Phase	3
Frequency (Hz)	60

TABLE 5.5-1 (SHEET 2 OF 2)

Jet Pumps

Number	20
Total jet pump flow (lb/h)	41.72×10^6
Throat inside diameter (in.)	6.86
Diffuser inside diameter (in.)	17
Nozzle inside diameter (representative) (in.)	3.4
Diffuser exit velocity (ft/s)	14.7
Jet pump head (ft)	91.7

RRS Loop Block Valve

Type	Gate
Actuator	Motor operated
Material	Stainless steel
Shutoff leakage (cm^3/in./h)	2
Valve size diameter (in.)	28

TABLE 5.5-3

RWC SYSTEM EQUIPMENT DESIGN DATA

Main Cleanup Recirculation Pumps

Number required (one is a backup)	1 of 2
Capacity (each) (%)	100
Discharge flow per pump at 545°F (gal/min)	270
Design temperature (°F)	575
Design pressure (psig)	1400
Differential head at rated flow (ft)	500

Heat Exchangers

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

Filter-Demineralizers

Number required	2
Capacity (each) (%)	50
Design flow per unit (gal/min)	101
Effluent conductivity, (µmho/cm at 25°C)	< 0.1
Effluent pH at 25°C	6.5 to 7.5
Effluent insolubles ((ppb) measured as residue on 0.45-micron filter paper)	< 10
Design temperature (°F)	150
Design pressure (psig)	1400
Time to backwash and precoat (min)	≤ 60

TABLE 5.5-4 (SHEET 1 OF 4)

LIMITORQUE SEISMIC AND ENVIRONMENTAL TEST REPORT INDEX[(a)]

Report Title and Date	Test Agency Report No.	Date	Unit	Motor	Radiation Level	Test Base
DC Test 1971 12/71	Franklin Institute F-C3117	11/16/71	SMB-0-25	Peerless Class H	---	6 days - 145°F - 100% RH Unit cycled twice 145°F - time 0 298°F - 5 s from 0 Hold 298°F - 3 h from 0 Hold 281°F - to 6 h from 0 Hold 265°F - to 24 h from 0 Unit cycled 8 times
Class B Steam Test 2/72	Franklin Institute F-C3271	1/2/72	SMB-0-10	Reliance Class B w/brake	---	Ambient - time 0 210°F - 1 h from 0 Hold 212°F - to 6 h from 0 to 155°F - in 3 h Hold 155°F - to 12 h from 0 Unit cycled 11 times
BWR Test 9/72	Franklin Institute F-C3441 or 600376A	7/31/72 - 8/30/72	SMB-0-25	Reliance Class RH	200 M rads	Per proposed IEEE 382 (Equivalent IEEE 382-72)
PWR Test 12/9/75	Limitorque Corporation 600456	6/7/74 - 11/22/74	SMB-0-40	Reliance Class RH	204 M rads	IEEE 382-72 - Table I
Class B Outside Containment	Limitorque Corporation B0003	11/13/74 - 1/23/75	SMB-0-25	Reliance Class B	20 M rads	Age - 165°F, 100% RH, 200 h - 200 cycles; 1800 cycles at room ambinet 120°F - time 0 250°F - 10 s Hold 250°F - to 30 min from time 0 to 120°F - to 2 h from time 0 120°F to 250°F - 10 s transient Hold 250°F - to 24 h from time 0 Hold 200°F - to 16 days from time 0 Unit cycled 5 times

TABLE 5.5-4 (SHEET 2 OF 4)

Report Title and Date	Test Agency Report No.	Date	Unit	Motor	Radiation Level	Test Base
DC Test	Limitorque Corporation B0009	9/2/75 - 11/3/75	SMB-0-25	Peerless Class RH	10 M rads	Age - Motor 180°C for 100 h 2000 cycles at ambient 120°F - time 0 to 340°F - 1 h from time 0 Hold 330°F - to 4 h from time 0 Hold 310°F - to 7 h from time 0 Hold 212°F - to 25 h from time 0 Unit cycled 6 times
Test of LVC for General Require-ments AC Test	Limitorque Corporation 600198 Addendum I Seismic Test to 5.3 g	10/31/68 9/29/69	SMB-0-15 Brake/Motor	Reliance Class H Reliance Class H w/Brake	---	Reference IEEE Subcommittee 2 Level 4 Standard Draft dated 6/7/68 1 h - 329°F 2 h - 312°F 2 h - 300°F 19 h - 272°F
1/2/69	259A-4723-Issue No. 2	8/20/70				6 days - 251°F Total - 7 days

Electric Operators Seismic Test Report Index

Unit Size[b]	Test Facility	Report No.	Report Date	Test Base	G-Level Each Axis
SMB-0-25	Lockheed Electronics	2768-4768A	10/21/71	Uniaxial	5
SMB-0-25 + Brake	Lockheed Electronics	2768-4768	10/21/71	Uniaxial	5.3
SMC-000-5	Ogden	7K112-11	11/27/72	Uniaxial	5.5 nominal
SMB-0-25	Ogden	7K112-11	11/27/72	Uniaxial	5.5 nominal
SMB-0-40	Lockheed Electronics	3521-4811	6/17/74	Uniaxial IEEE 344-71	6

TABLE 5.5-4 (SHEET 3 OF 4)

Electric Operators Seismic Test Report Index (Continued)

Unit Size[(b)]	Test Facility	Report No.	Report Date	Test Base	G-Level Each Axis
SMB-0-25	Aero Nav	5720	1/6/75	IEEE 344-75 Modified	5 at 3 g 1 at 6 g
SMB-000-5	Aero Nav	5721	1/7/75	IEEE 344-75 Modified	5 at 3 g 1 at 6 g
SMB-1-40	Aero Nav	5722	1/7/75	IEEE 344-75 Modified	5 at 3 g 1 at 6 g
SB-3-100	Aero Nav	5770	10/20/75	IEEE 344-75	5 at 3 g 1 at 6 g
SMB-000-5	Aero Nav	5771	10/17/75	IEEE 344-75	1 at 6 g 5 at 3 g
SMB-3-100	Aero Nev	5773	10/16/75	IEEE 344-75	2 at 5 g 1 at 6 g
SB-0-25	Aero Nav	5774	10/22/75	IEEE 344-75	2 at 5 g 1 at 6 g
SMB-0-25DC	Aero Nav	5772	10/21/75	IEEE 344-75	2 at 5 g 1 at 6 g
SMB-1-100 "E" Line Motor	Aero Nav	5775	10/22/75	IEEE 344-75	2 at 5.3 g 1 at 6.3 g
SMB-5T-250DC	Wyle Labs	43059-1	10/6/75	Spec biaxial	1 g
SMB-0-25DC	AEL	75-149ET	10/29/75	Single axis	4 g
SMB-5T-250AC	Wyle Labs	43059-02	10/30/75	Single axis	6 g

Electric/Manual Operator Seismic Test Report Index

Unit Size[(b)]	Test Facility	Report No.	Report Date	Test Base	G-Level Each Axis
SMB-000-2/HOBC	Lockheed Electronics	2773C-4773	5/3/72	Single axis	4.4 g

TABLE 5.5-4 (SHEET 4 OF 4)

Electric/Manual Operator Seismic Test Report Index (Continued)

Unit Size[b]	Test Facility	Report No.	Report Date	Test Base	G-Level Each Axis
SMB-0-25/H3BC	Lockheed Electronics	2786-4786-Issue No. 2	9/5/72	Single axis	3 g
SMB-3-100-H5BC	Lockheed Electronics	2786-4-4786	2/1/73	Single axis	4 g
SMB-0-H3BC	Lockheed Electronics	2786-3-4786	2/6/73	Single axis	3.7 g
SMB-1-25/H4BC Standard Adapter	Aero Nav	506167-5	12/17/75	IEEE 344-75 Fragility test	8.0 g Capacity of machine
SMB-00-15/H3BC Spec Steel Adapter	Aero Nav	5-6167-4	12/16/75	IEEE 344-75	2 at 5.3 g 1 at 6.3 g

Manual Operators Seismic Test Report Index

Unit Size[b]	Test Facility	Report No.	Report Date	Test Base	G-Level Each Axis
H1BC	Lockheed Electronics	2553-4737	12/28/70	Single axis	5.3 g
H1BC	Lockheed Electronics	2786-5-4786	1/30/73	Single axis	4.6 g
H4BC	Lockheed Electronics	2786-6-4786	1/30/73	Single axis	4.6 g
H6BC	Lockheed Electronics	2786-7-4786	1/30/73	Single axis	3.6 g

a. As of 7/26/75, seismic tests were completed to IEEE 344-1975 for both SMB and SB units to 6.0 g vertical and 3.2 g horizontal. Since no cross coupling was noted between axes, the test qualifies the SMB/SB to 6.0 g in both the vertical and horizontal axes. Maximum g-level dwells in each of the three axes qualify the units for any mounting position.

b. The levels tested for the unit sizes above are not to be construed as applicable to all sizes and combinations of SMB/H-BC units. The maximum g level allowed for all sizes is limited to 3 g in any axis.

TABLE 5.5-5 (SHEET 1 OF 8)

LOW-LOW SET FMEA FOR FUNCTIONAL COMPONENTS

Failure Mode[a]	System Lineup[b]	Effect[c]	When Observed	Functional Failure[c]
System Component: Pressure Switches PS1-PS11			Function: SRV Open Sensor	
A1	A11	Valve operates normally.	Surveillance test once/operating cycle	None
A2	N2, T1, O1, O2, N2, S2	Valve operates normally.	Trip unit surveillance test once/month	None
	N2 (Note 1) S2 (Note 1)	All LLS valves. EA or EVO.	(Note 1)	EA or EVO All valves (Note 2)
	T2	K9 picks up & one valve opens.	During monthly surveillance	IVO One valve
System Component: Pressure Transmitters PT1 and PT2			Function: Reactor pressure sensors	
B1	A11	No valve opening possible. Analog trip trouble annunciator ON. Trip unit meter downscale.	Immediately	FTO One valve
B2	N1, N2, T1, T2, O1, O2	Analog trip trouble annunciator ON. Valve operates normally. Trip unit meter upscale.	Immediately	None
B2 (PT1 only)	S1	One channel arms & annunciates.	Annunciation when SRV is manually actuated	IA One channel
	S2	Another SRV opens.	Annunciation when SRV is manually actuated	IVO One SRV
System Component: Trip Units MTU1, MTU2, and STU 1			Function: Reactor pressure trip setpoints	
C1	A11	Same as B1.	Immediately	FTO One valve
C2	Same as B2	Same as B2.	Immediately	Same as B2
C2 (MTU1 only)	S1, S2	Same as B2 (PT1 only).	Same as B2	Same as B2

TABLE 5.5-5 (SHEET 2 OF 8)

Failure Mode[a]	System Lineup[b]	Effect[c]	When Observed	Functional Failure[c]
System Component: Relays - K1, K2, K4, K5, K10, K11, and K12			Function: Divisional isolation for annunciators or indicators	
D1, D2	All	False annunciation or indication. Valve operates normally.	Upon daily or monthly surveillance	None
System Component: Relay K6			Function: Arming setpoint relay	
D1, D3	N1, N2, T2, S1, S2	Valve operates normally. Test light does not come ON.	Monthly surveillance test	None
D1 & D3 arming contact	O1, O2	K9 does not pick up & arm channel. Valves do not close.	When valve operates	FTO One valve
D3 contact with K12	O1, O2	Test indicator fails to function.	Monthly surveillance	None
D2, D4	N1, N2, T1, T2, O2, O1	Valve operates normally.	Monthly surveillance	None
D2 & D4 arming contact	S2	Channel arms & valve opens.	Upon SRV actuation or monthly surveillance	IA IVO One valve
	S1	Channel arms. LLS channel armed. Annunciator ON.	Immediately upon manual SRV actuation	IA One valve
D5 not used				
System Component: Relays K7 and K8			Function: LLS trip setpoint	
D1, D3	N1, N2, T1, T2, S1, S2, O2	Valve operates normally.	Monthly surveillance	None
D1 & D3 contact in series with K14 or K15	O1	Valve fails to open.	When valves fails to open	FTO One valve
D2, D4	N1, N2, T1, T2, O1, O2, S1, S2	Valve operates normally.	Monthly surveillance	None
D5	All	Valve operates normally.	Monthly surveillance	None

TABLE 5.5-5 (SHEET 3 OF 8)

Failure Mode[a]	System Lineup[b]	Effect[c]	When Observed	Functional Failure[c]
System Component: Relay K9			Function: Logic arming relay	
D1, D3	N1, N2, T1, T2, S1, S2	Valve operates normally.	Monthly surveillance	None
D1 & D3 for contact in series with K13	O1, O2	Valve fails to open. Annunciator OFF.	During arming logic test. LLS channel armed	FTO One valve
D3 for contact in series with S5	O1, O2	Valve does not stay armed; so, it closes at arming pressure setpoint.	Monthly during surveillance or during operation	(Note 3)
D3 for contact in series with K11	O1, O2	Valve operates normally but channel armed annunciator stays OFF.	When annunciator stays off but valve operates	None
D3 for contact in other channel in same division	O1, O2	Does not seal in other channel pressure switch sense.	During outage testing	None
D5 not used				
D2	All except T2, N2, S2	Annunciator indicates arming.	Immediately	IA One channel
	N2, S2, T2	Valve opens, channel arms, & annunciator is ON.	Immediately upon annunciation or tests	IVO One channel
D2	(Note 4)	Same as T2 except, if reactor pressure reaches arming setpoint without opening SRV, all LLS valves open. Channel armed annunciator ON.	(Note 4)	EVO All LLS Valves (Note 4)
D4 contact in series with solenoid	N1, T1, O1, O2, S1	Valve operates normally.	Monthly surveillance	None
	N2, S2, T2	Valve opens. L5 does not extinguish.	During monthly surveillance	IVO One valve

TABLE 5.5-5 (SHEET 4 OF 8)

Failure Mode[a]	System Lineup[b]	Effect[c]	When Observed	Functional Failure[c]
System Component: Relay 9 (continued)			Function: Logic arming relay	
	N2, S2, T2	Valve opens. L5 does not extinguish.	During monthly surveillance	IVO One valve
D4 contact in series with K11	N1, N2 T2, S1	Valve operates normally. Channel armed annunciator ON.	Immediately	None
	T1, O1, O2	Valve operates normally.	When annunciator does not go off & channel is reset	None
D4 contact in series with S5	Same as D2	Same as D2 except relay drops out when S5 is pushed & picks up when S5 is released.	Same as D2	Same as D2
D4 contact interconnect between channels	N1, S1, T1, O1, O2, N2, S2	Valve operates normally.	Once/operating Cycle surveillance	None
	T2	Channel arms or valve opens.	During monthly surveillance	IA or IVO One valve
System Component: 125 V-dc battery 125 V-dc contractor 24 V-dc power supply			Function: Provide logic and trip unit power	
E1, E2	All	No effect on valve operation. Power fail and/or analog trip trouble annunciators ON.	Immediately	None
E3	All	One valve in same division does not open. Power loss annunciator ON.	Immediately	FTO One valve
E4	All	One valve does not open. Analog trip trouble annunciator ON. LLS channel armed. Annunciator OFF.	Immediately	FTO One valve
System Component: Lights L1, L2, L3, and L4			Function: Test and failure condition indication	
F1	All	Valve operates normally. Light OFF.	L1, L2-daily surveillance; L3, L4-monthly surveillance	None

TABLE 5.5-5 (SHEET 5 OF 8)

Failure Mode[a]	System Lineup[b]	Effect[c]	When Observed	Functional Failure[c]
System Component: Lights L1, L2, L3, and L4 (continued)			Function: Test and failure condition indication	
F2	All	Blows fuse so all lights are OFF. Valve operates normally.	Daily surveillance	None
System Component: Light L5			Function: LLS logic test	
F1	All	Valve operates normally.	Monthly surveillance	None
F2 (Note 5)	N1, N2, T2, O1	Valve operates normally.	Monthly surveillance	None
	T1	Valve opens if K9 is energized.	Immediately during surveillance test	IVO One valve
	O2	K9 is armed, so, one valve is stuck open until reset by operator.	During pressurization transient	SOV One valve
System Component: Switches S1, S2, S3, and S6			Function: Power test card out-of-file test	
G1	All	Valve operates normally. Analog trip trouble or power loss annunciators ON.	Immediately	None
G2	All	Valve operates normally. Analog trip trouble or power loss annunciators do not go ON when testing function.	Monthly surveillance	None
System Component: Switch S4			Function: LLS logic test	
G1	All	Valve operates normally	Monthly surveillance	None
G2	N1	K9 pick ups & latches in arming one channel. LLS channel armed, annunciator ON, does not RESET.	Immediately (Note 6)	IA One channel
	N2, S2	Failure in line N2; valve operates normally.	Immediately	None
		If failure exists (Note 7) during N1, channel is armed when pressure increases to N2. Valve opens.	One valve	IVO (Note 7)
	T1, T2, O1, O2, S1	Valve operates normally. No indication until K7 & K8 drop out. Then it is in the N1 or N2 line up.	Immediately (Note 6)	None

TABLE 5.5-5 (SHEET 6 OF 8)

Failure Mode[(a)]	System Lineup[(b)]	Effect[(c)]	When Observed	Functional Failure[(c)]
System Component: Switch S5			Function: Reset armed channel	
G1	All	Arming relay K9 does not latch in once armed. The one valve involved can only open above the arming enable setpoint and close below the same trip unit reset point if higher than normal. Valve does not operate setpoints. Armed annunciator goes ON & OFF with pressure.	Monthly surveillance or when valve operates	One valve opens & closes at wrong setpoint.
G2	All	K9 arms normally. Valve opens & closes normally but arming relay cannot be reset so remains armed. Channel armed annunciator stays ON.	Monthly surveillance or when operator tries to reset channel	No arming reset. One valve

NOTES:
1. The failure listed occurs during a transient when reactor pressure increases to its scram setpoint but the SRVs have not lifted. This condition is not expected during plant operation. The stuck-closed contact, i.e., failure mode A2, produces a false indication of a SRV opening, and two LLS valves either arm, or operate, depending on LLS setpoints. An opening produces SRV opening signals in the other division, thus, four LLS valves could be armed.
2. The failure mode A2, coupled with a pressurization transient, contributes to early arming and opening of SRVs. Under these conditions of early LLS initiation, the LLS performs its function to relieve reactor pressure and prevents early subsequent actuations as designed.
3. After the first pop, the valve closes at the arming permissive pressure. For subsequent pops, the valve opens simultaneously with another valve if another LLS valve has an opening setpoint above or near the arming permissive pressure.
4. The failure occurs during a pressurization transient, when reactor pressure increases to its scram setpoint but the SRVs have not lifted, a condition which is not expected during plant operation. This failure mode, coupled with a transient, contributes to an early LLS initiation. EVOs result in the LLS performing its function to relieve reactor pressure.
5. L5 is a neon light with a limiting resistor, and a short requires shorting in both the lamp and the resistor.
6. The switch is also used for power test. If contacts stick closed, the power loss annunciator does not reset.
7. IVO only occurs when the failure is coincident with a change in reactor pressure, i.e., changing from N1 to N2.

TABLE 5.5-5 (SHEET 7 OF 8)

---

a. LLS Components and Their Failure Modes

A. Pressure switches (normally open contacts)**
   A1. Contacts stick open, inadvertently open or fail to close.
   A2. Contacts stick close or fail to open.*

B. Transmitter
   B1. Downscale failure**
   B2. Upscale failure**

C. Trip unit
   C1. Downscale failure**
   C2. Upscale failure**

D. Relay
   D1. All contacts stuck in deenergized state or coil mechanism fails.
   D2. All contacts stuck in energized state.*
   D3. One contact stuck in deenergized state.
   D4. One contact stuck in energized state.
   D5. One normally closed contact opens.*

E. Power supply and battery
   E1. Power circuit short fails power.
   E2. Power circuit open fails power.
   E3. Logic circuit short blows fuse.
   E4. Trip unit circuit short blows fuse.

F. Light
   F1. Light opens.
   F2. Light shorts.

G. Switch
   G1. Contacts stick open or fail open.
   G2. Contacts stick closed.*

b. System Lineups Identification

N. Normal status (standby)
   N1. All relays are deenergized
   N2. K7 and K8 are energized (reactor pressure above LLS setpoints and below the arming permissive).

O. Operational status
   O1. K9, K7, and K8 are energized (open valve).
   O2. K9 is energized.

TABLE 5.5-5 (SHEET 8 OF 8)

S. SRV manual test status
   - S1. Same as N1 with SRV manually opened.
   - S2. Same as N2 with SRV manually opened.

T. Testing status
   - T1. K9 is energized.
   - T2. K7, K8, and K6 are energized (calibrating trips during N2).

c. <u>Functional Failure Modes Identification</u>

FTO - Failure to open on demand
SOV - Stuck-open valve
IA - Inadvertent arming
IVO - Inadvertent valve opening
EA - Early arming
EVO - Early valve opening

---

* Inadvertent shorting or closing of normally unconnected points is not considered a single failure in this FMEA.

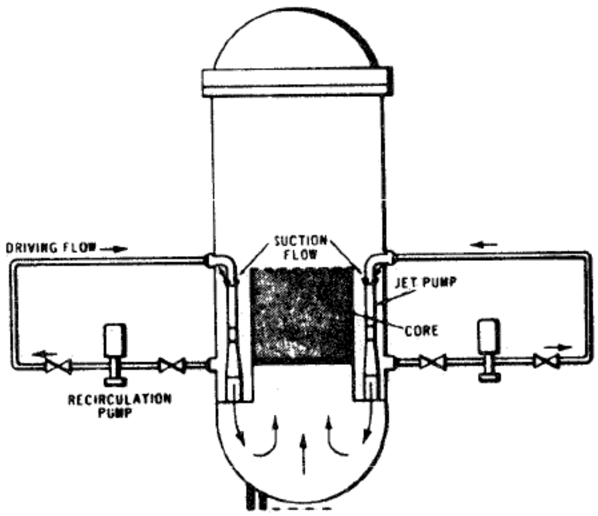
** Setpoints account for nominal drift; large drift is considered an upscale or downscale failure.

TABLE 5.5-6

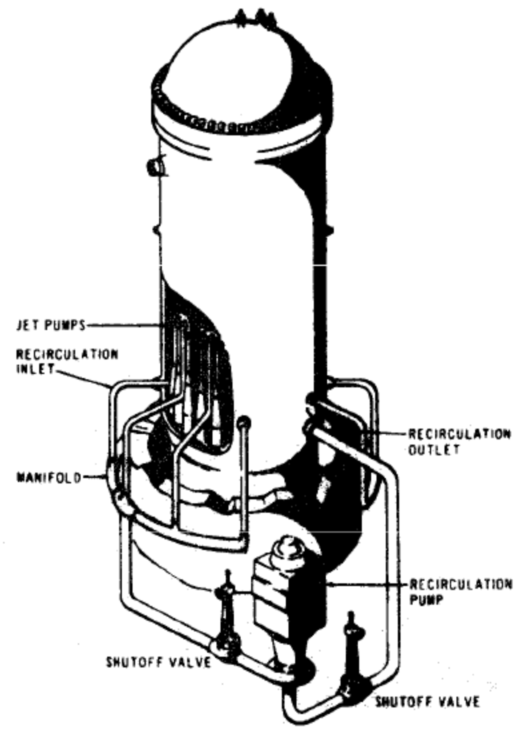
LLS SRV SYSTEM FOR HNP-2

	SRVs										
	A	B	C	D	E	F	G	H	K	L	M
Pressure relief function	X	X	X	X	X	X	X	X	X	X	X
ADS function	X	-	X	-	X	-	-	X	X	X	X
Valve group	II	I	II	I	III	I	I	III	II	III	II
Steam pilot mechanical opening setpoint (psig)	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Electrical backup to mechanical opening setpoint (psig)	1130	1120	1130	1120	1140	1120	1120	1140	1130	1140	1130
LLS relief channel	-	A	-	D	-	C	B	-	-	-	-
LLS opening allowable value (psig)[a]	-	≤ 1010	-	≤ 1050	-	≤ 1040	≤ 1025	-	-	-	-
LLS closing allowable value (psig)[a]	-	≤ 860	-	≤ 900	-	≤ 890	≤ 875	-	-	-	-

a. LLS setpoints are interchangeable among LLS valves.



ELEVATION



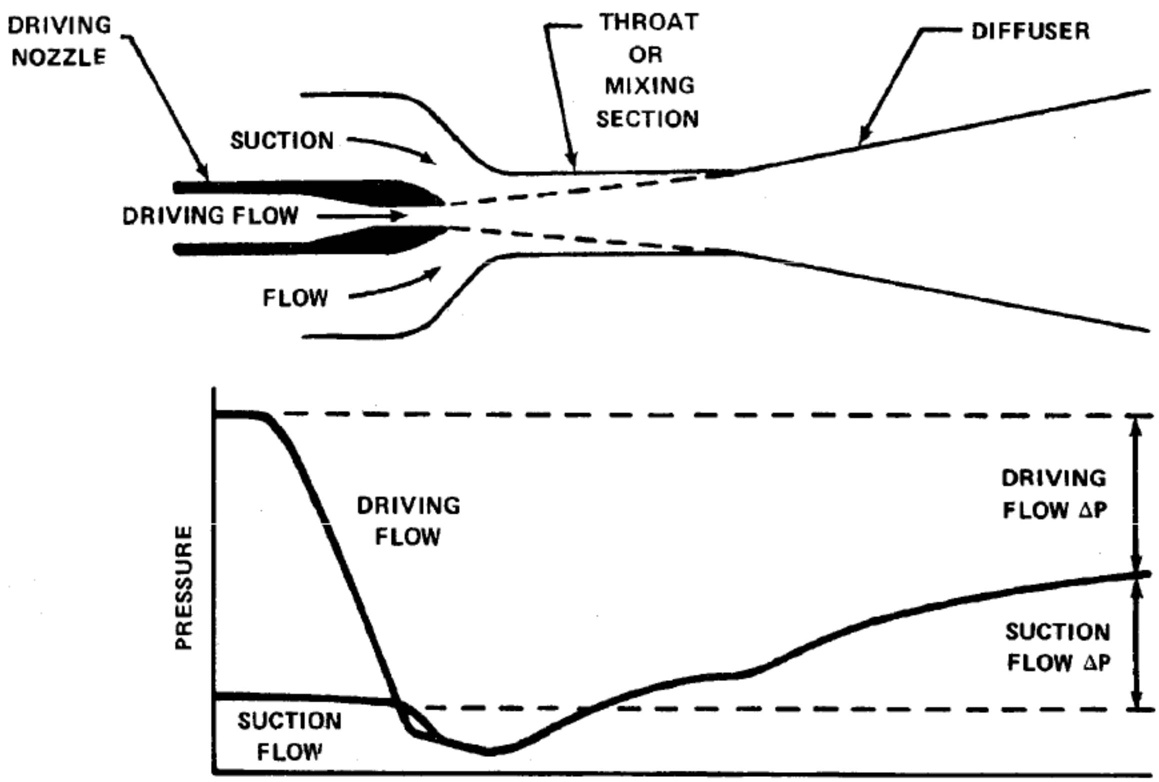
ISOMETRIC

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

REACTOR RECIRCULATING SYSTEM
ELEVATION AND ISOMETRIC

FIGURE 5.5-1



ACAD 2050502

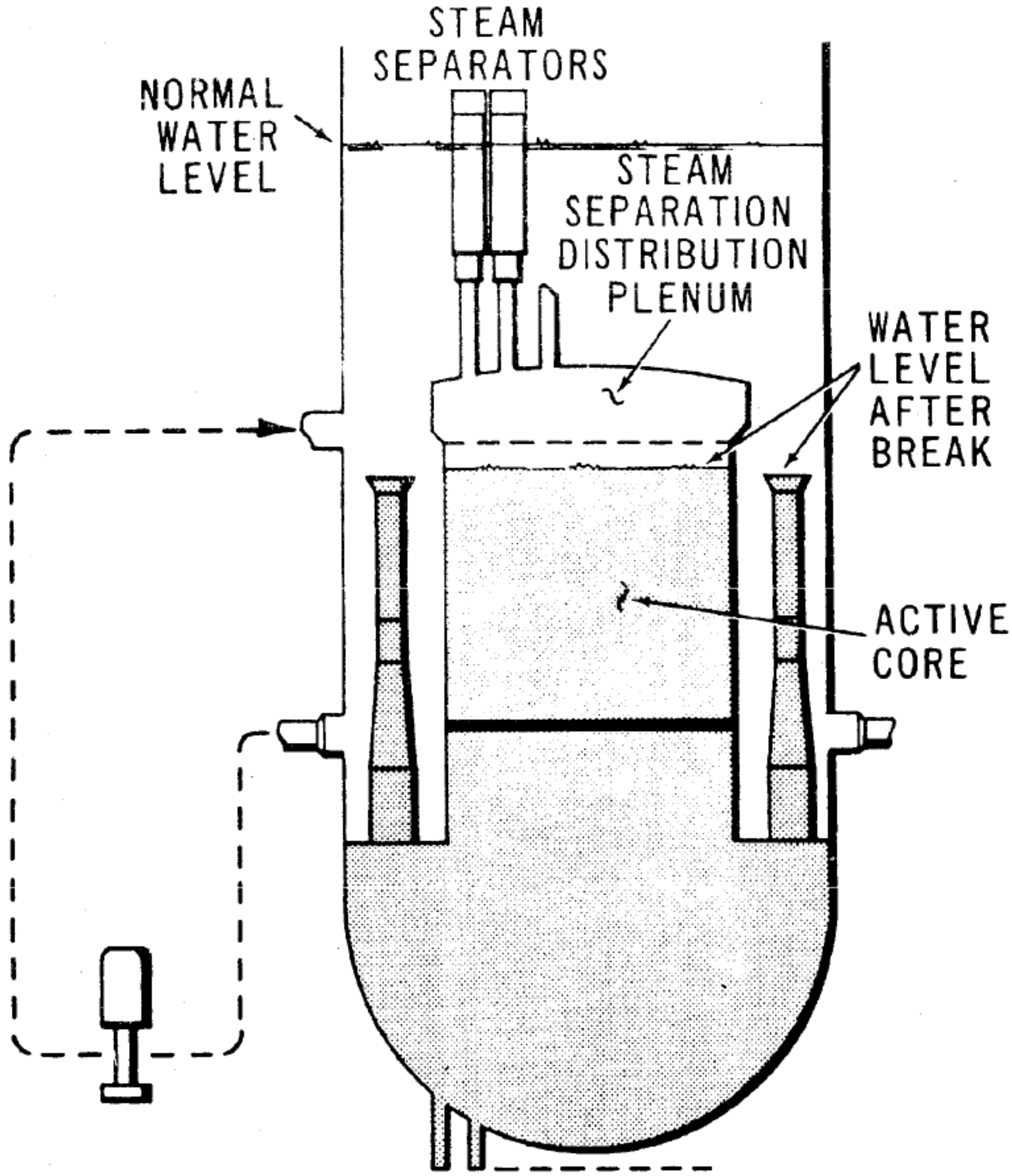
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

OPERATING PRINCIPLE OF JET PUMP

FIGURE 5.5-2



ACAD 2050503

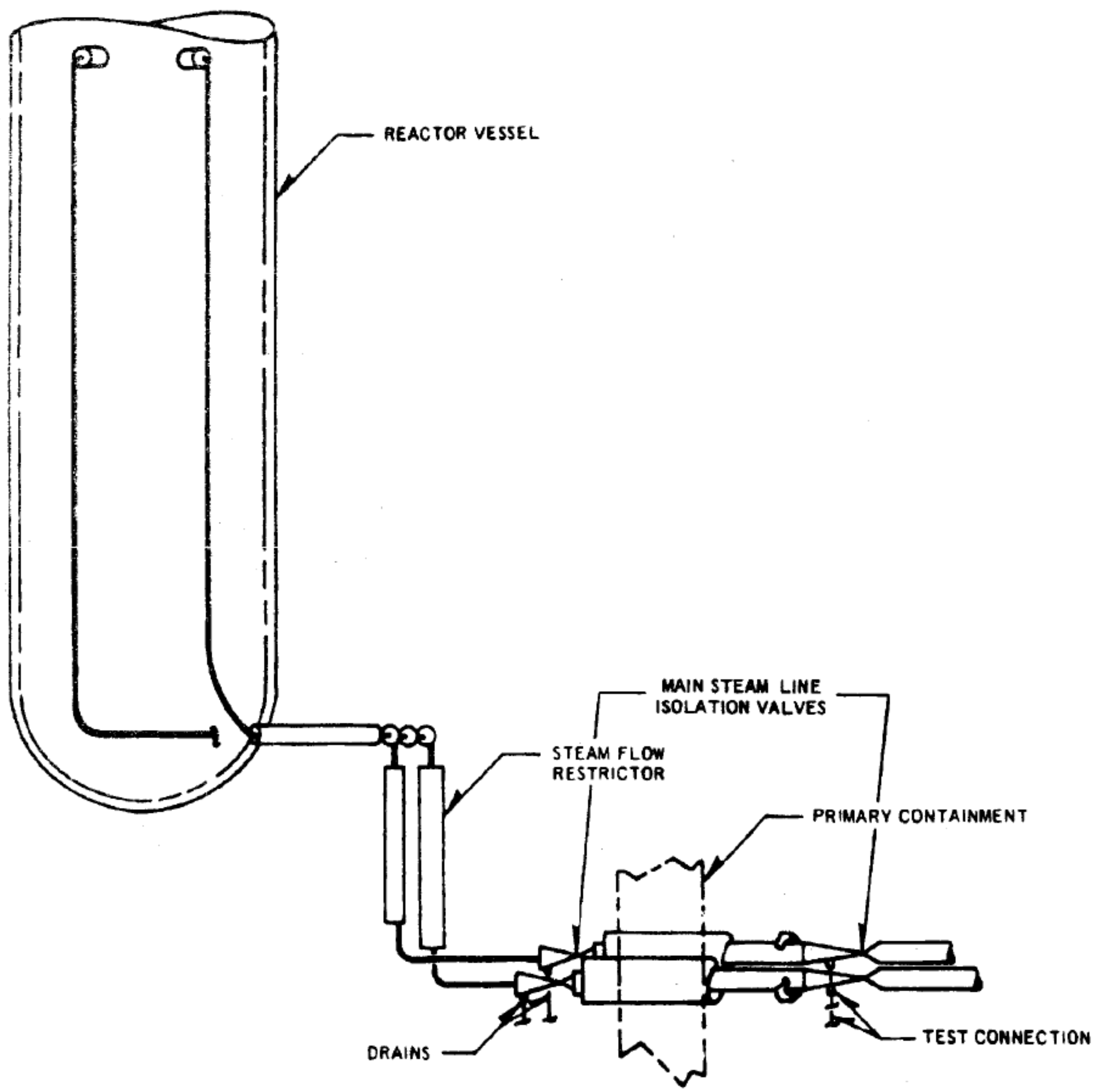
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION SYSTEM-CORE FLOODING CAPABILITY

FIGURE 5.5-3



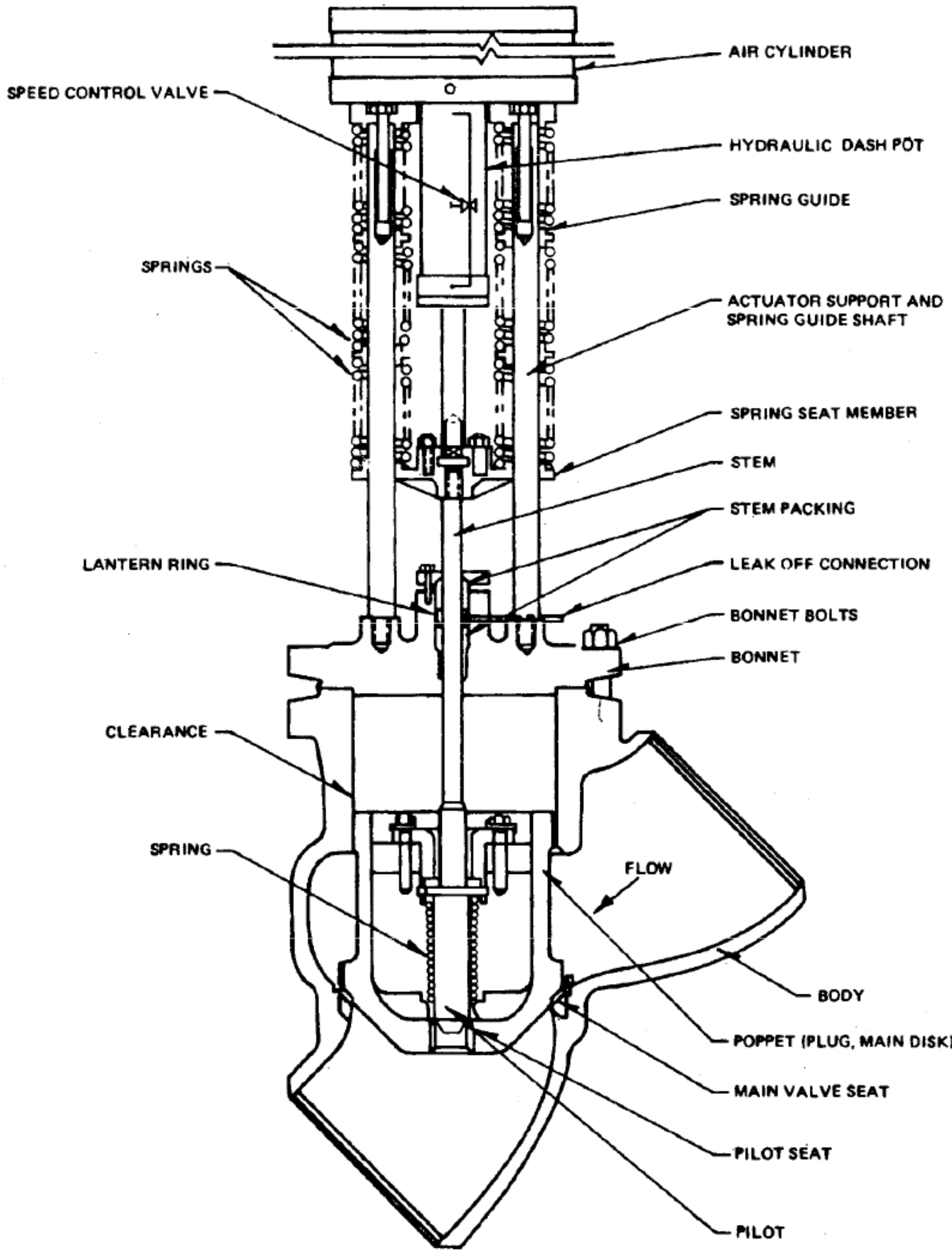
ACAD 2050504

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MAIN STEAM LINE FLOW RESTRICTOR LOCATION

FIGURE 5.5-4



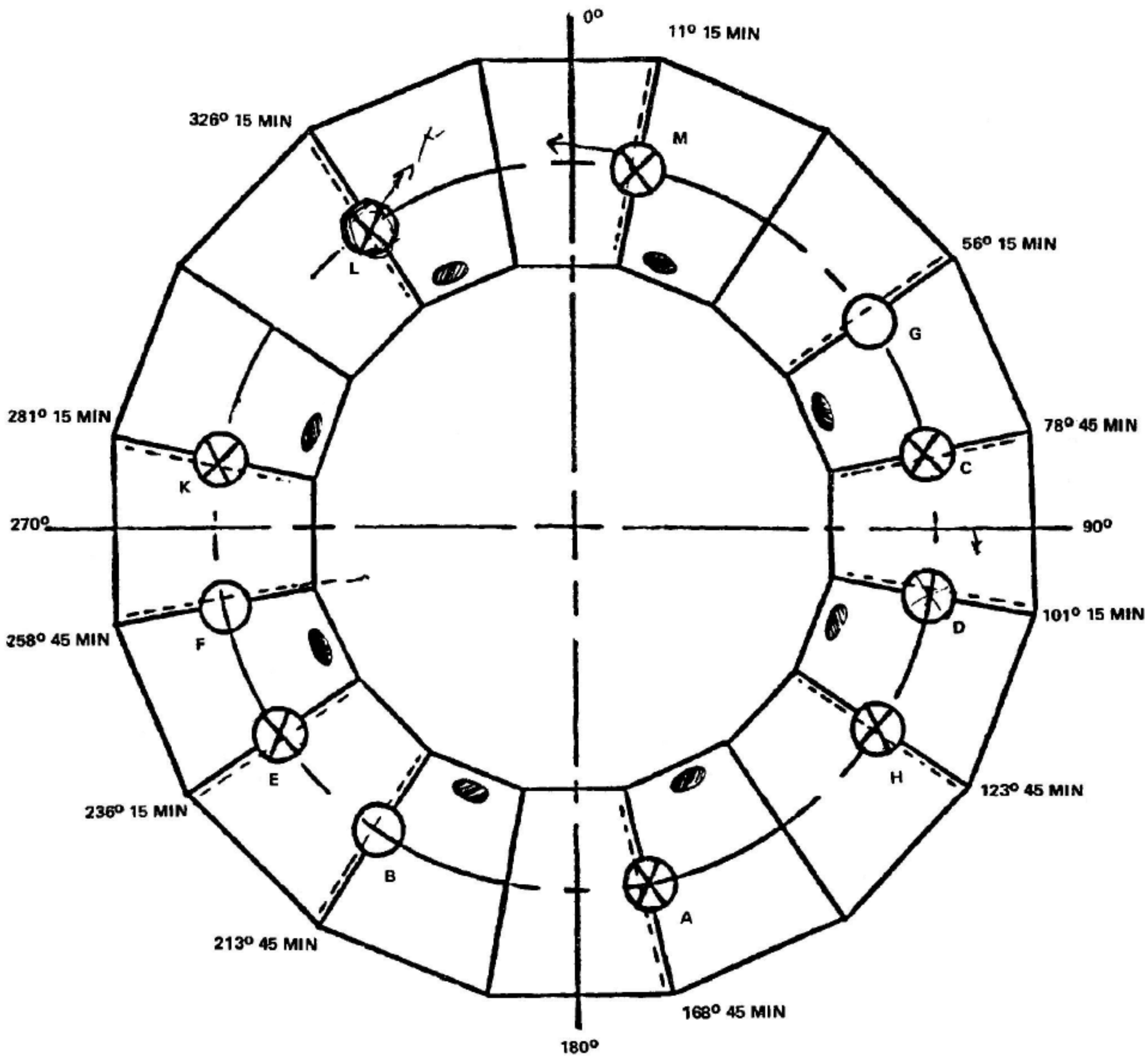
ACAD 2050505

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MIAN STEAM LINE ISOLATION VALVE

FIGURE 5.5-5



ACAD 2050506

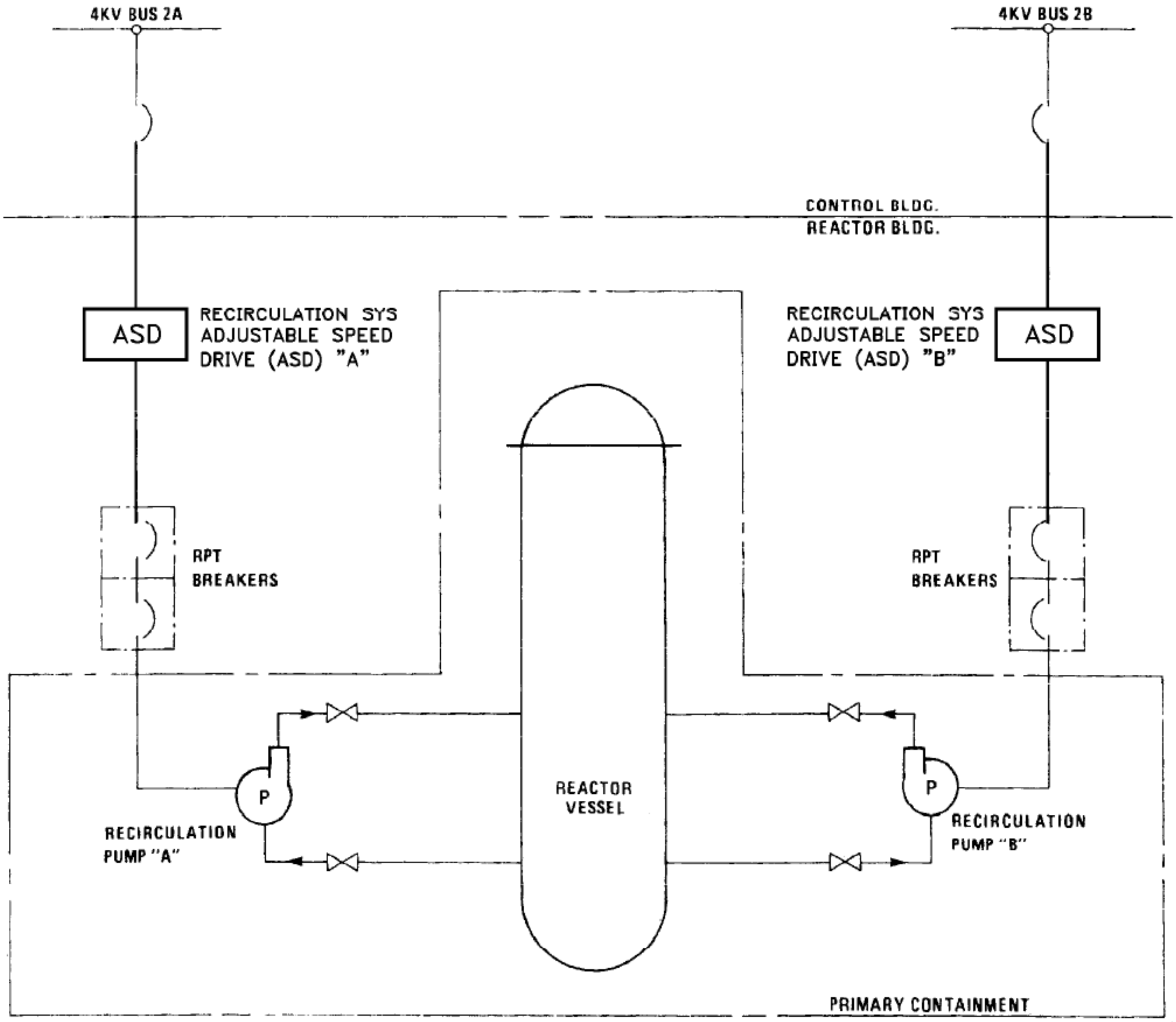
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LOCATION OF RELIEF VALVE EXITS
IN THE TORUS

FIGURE 5.5-6



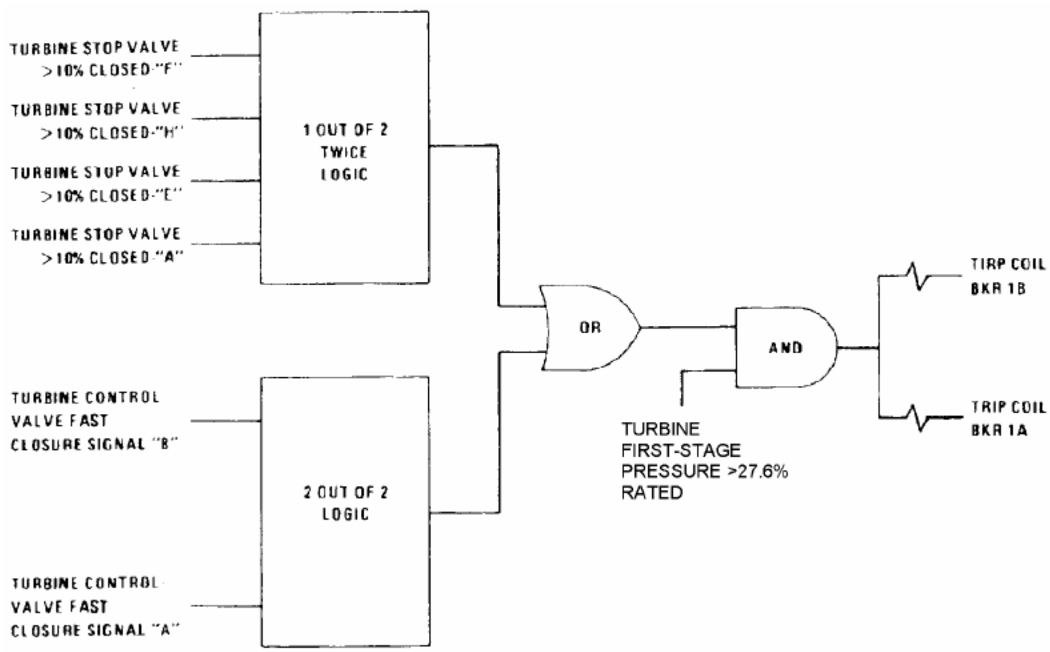
ACAD 2050508

REV 27 10/09

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION SYSTEM WITH RECIRCULATION PUMP TRIP

FIGURE 5.5-8



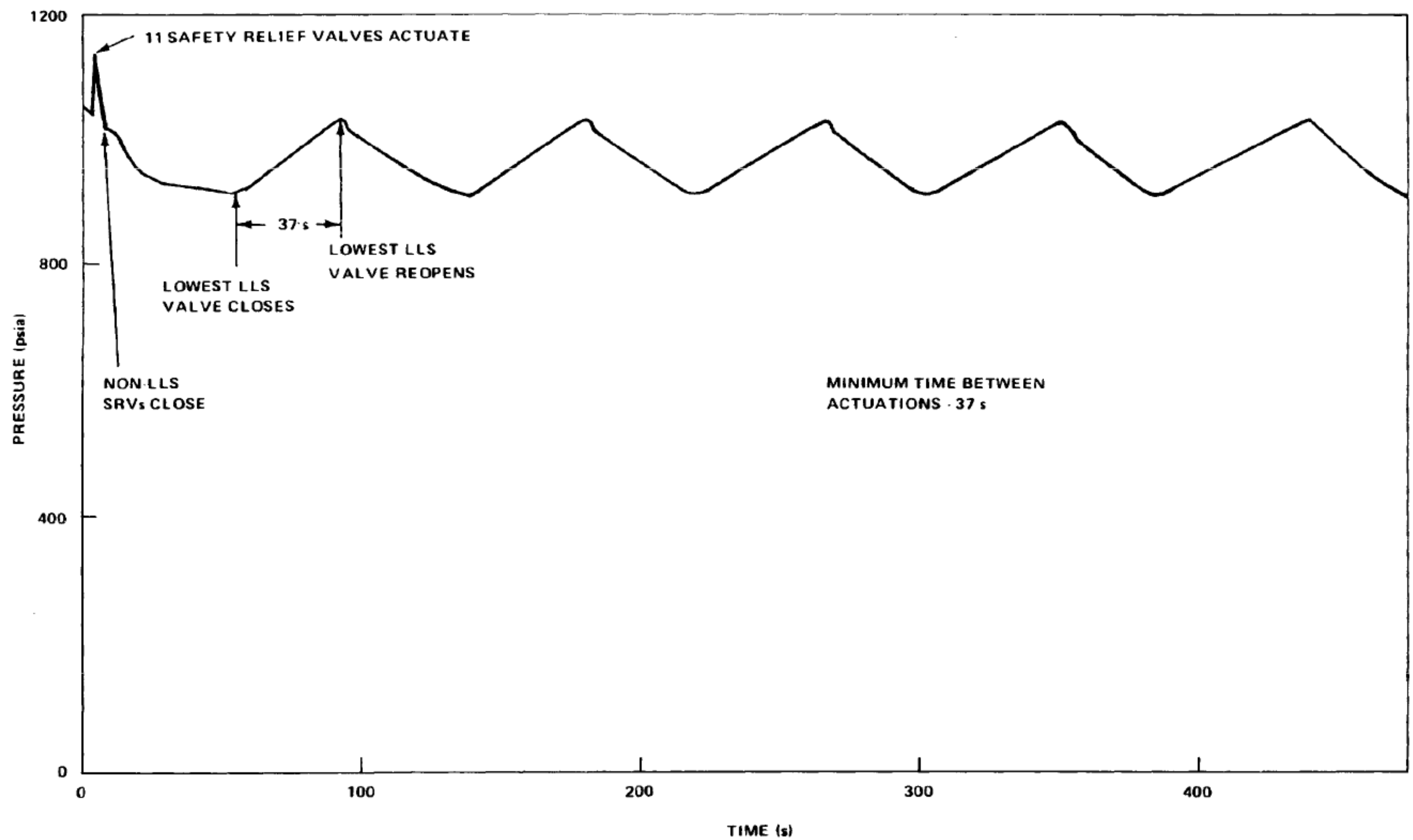
ACAD 2050509

REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION PUMP TRIP CONTROL

FIGURE 5.5-9



ACAD 2050510

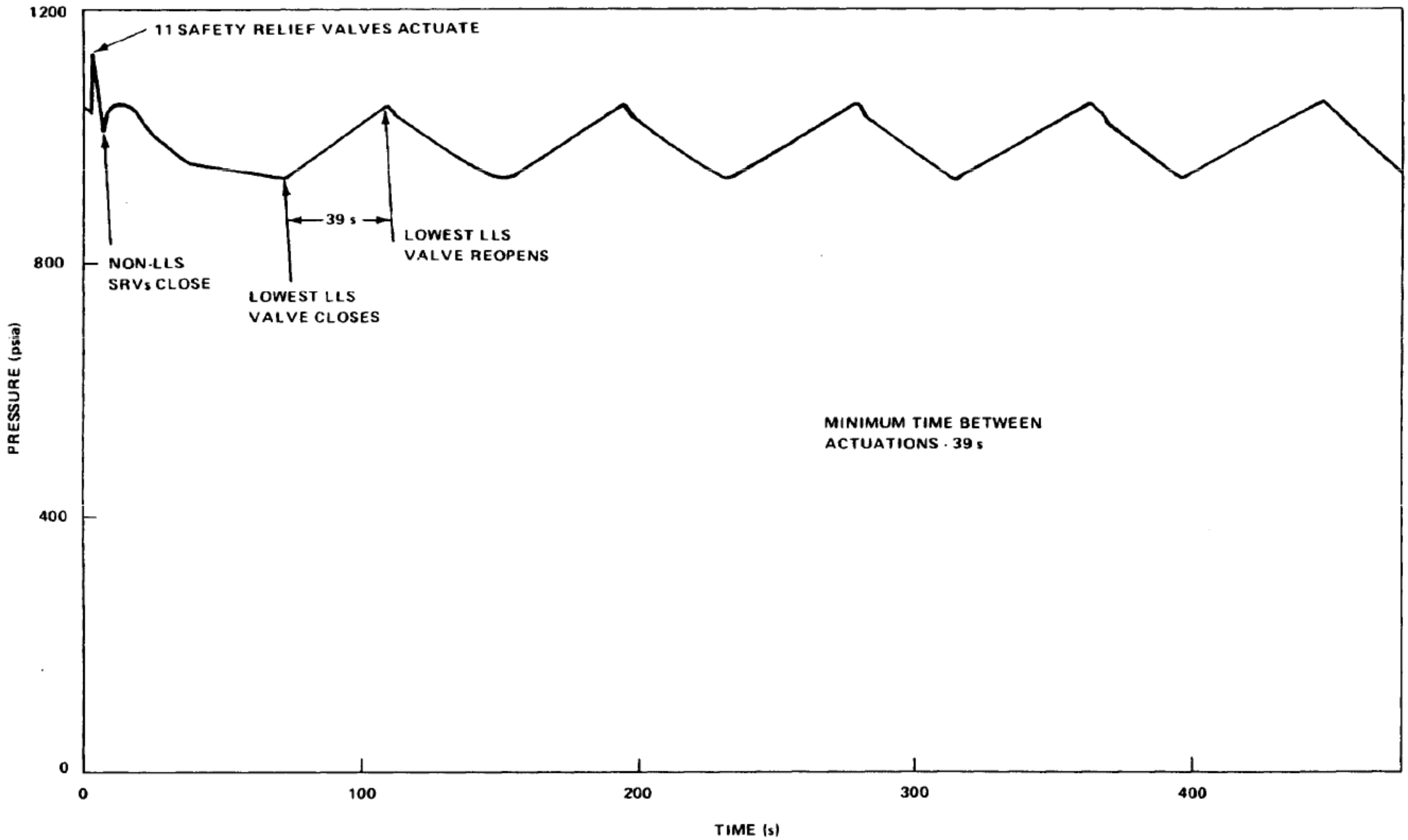
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SYSTEM RESPONSE FOR LIMITING EVENT WITH FOUR-VALVE LLS

FIGURE 5.5-10



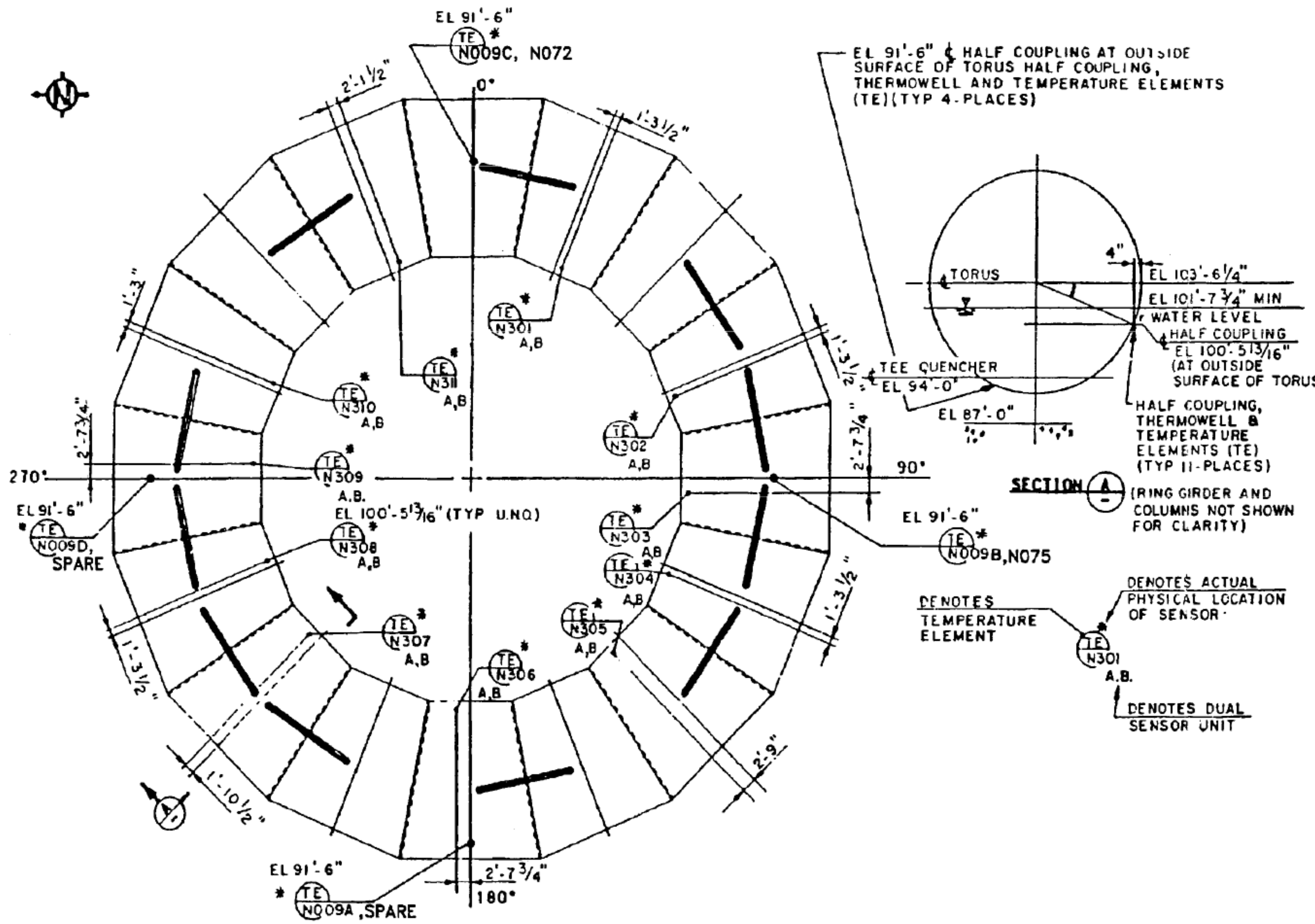
ACAD 2050511

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SYSTEM RESPONSE FOR LIMITING EVENT WITH SINGLE FAILURE (ONLY TWO LLS VALVES OPERABLE)

FIGURE 5.5-11



PLAN

ACAD 2050512

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SUPPRESSION POOL TEMPERATURE SENSOR LOCATIONS

FIGURE 5.5-12

5.6 INSTRUMENTATION REQUIREMENTS

The functional requirements for the reactor coolant system instrumentation are discussed in the following subsections. A discussion of the design and logic of the instrumentation is discussed in chapter 7.

5.6.1 NEUTRON MONITORING SYSTEM

This system is described in subsection 7.6.2.

5.6.2 REACTOR PRESSURE VESSEL (RPV) INSTRUMENTATION

RPV instrumentation is designed to provide the operator with sufficient indication of reactor core flowrate, RPV water level, RPV pressure, and nuclear system leakage to maintain proper operating conditions.

5.6.2.1 RPV Temperature

RPV temperature is determined on the basis of reactor coolant temperature. Temperatures needed for operation and for compliance with the technical specification operating limits are obtained from one of several sources depending on the operating condition. During normal operation, either the reactor pressure and/or the inlet temperature of the coolant in the reactor recirculation system loops can be used to determine the RPV temperature. Below the operating span of the temperature detectors in the RRS loop, the pressure is used for determining the temperature. Below 212°F the coolant temperature in the RPV, and thus the RPV temperature, is reasonably determined by the reactor water cleanup system inlet temperature.

5.6.2.2 RPV Water Level

The number of RPV water level indications is sufficient to provide the operator with information to determine the adequacy of the coolant inventory to cool the fuel. In addition, by verifying that RPV water level is not rising to an abnormally high level, the operator is assured that turbines are not endangered by the possibility of water carried into the steam lines.

5.6.2.3 RPV Coolant Flowrates and Differential Pressures

Flow instruments, differential pressure instruments, and recorders are provided so that the core coolant flowrates and the hydraulic performance of RPV internals can be determined.

5.6.2.4 RPV Internal Pressure

Pressure switches, indicators, and transmitters detect RPV internal pressure from the same instrument lines used for measuring RPV water level.

5.6.2.5 RPV Top Head Flange Leak Detection

A connection is provided on the RPV flange into the annulus between the two metallic seal rings used to seal the RPV and top head flanges. This connection permits detection of leakage past the inner seal ring and is described further in subsection 5.2.7.

SUPPLEMENT 5A

SUMMARY TECHNICAL REPORT OF REACTOR VESSEL OVERPRESSURE PROTECTION (HNP-1 AND HNP-2)

This section describes the initial analysis for the Edwin I. Hatch Nuclear Plants HNP-1 and HNP-2. Subsequent analyses for reloads are given in table 15.1-1.

This report provides sufficient information and documentation to show compliance with all requirements of Article 9 of American Society of Mechanical Engineers (ASME) Pressure Vessel Code - Section III, 1968, Nuclear Vessels in the Area of the Vessel Overpressure Protection Design of the Nuclear Pressure Vessel. Included is the design basis for sizing of the dual purpose, combination safety relief valves, the overpressure protection analysis, and the analysis of the safety relief valve system availability. The effects on the vessel pressure transients of valve capacity are also shown.

5A.1 INTRODUCTION

The vessel overpressure protection system is designed to satisfy the requirements of Section III, Nuclear Vessels, of the ASME Boiler and Pressure Vessel Code. The general requirements for protection against overpressure as given in Article 9 of Section III of the ASME Code recognize that reactor vessel overpressure protection is one function of the reactor protection systems and allows the integration of pressure relief devices with the protection systems of the nuclear reactor. Hence, credit is taken for the scram protection system as a complimentary pressure protection device. The General Electric Company, however, provides analyses which take credit only for reactor protection signals which are indirectly derived. The Nuclear Regulatory Commission (NRC) has also adopted the ASME Codes as part of their requirements in the Code of Federal Regulations (10 CFR 50.55a).

5A.2 DESIGN BASIS

5A.2.1 SAFETY RELIEF VALVE SIZING

The safety relief valve capacity of HNP-1 and HNP-2 is sized to limit the primary system pressure, including transients, to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels. The essential ASME requirements, which are all met by this analysis, are stated in the following paragraphs.

A. *It is recognized that the protection of vessels in a nuclear power plant is dependent upon many protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices may not independently provide complete protection.*

B. *The safety relief valve sizing evaluation assumes credit for operation of the scram protective system which may be tripped by any one of three sources, i.e., a direct, flux, or pressure signal. The direct scram signal is derived from position switches mounted on the*

main steam isolation valves (MSIVs) or the turbine stop valves or from pressure switches mounted on the dump valve of the turbine control valve (TCV) hydraulic actuation system. The position switches are actuated when the respective valves are closing and following 10% travel of full stroke. The pressure switches are actuated when a fast closure of the control valves is initiated. However, according to General Electric policy, the safety valve sizing evaluation does not assume credit for direct scram, only for the indirect high neutron flux scram. Further, no credit is taken for power-operated pressure relieving devices. Credit is taken for the dual purpose safety relief valves in their ASME Code qualified mode of safety operation.

C. *The rated capacity of the pressure relieving devices is sufficient to prevent a rise in pressure within the protected vessel of more than 110% of the design pressure (1.10 x 1250 psig = 1375 psig). Full account is taken of the pressure drop on both the inlet and discharge sides of the valves. All combination safety relief valves discharge into the suppression pool through a discharge pipe from each valve which is designed to achieve sonic flow conditions through the valve, thus providing flow independence to discharge piping losses.*

D. *The nominal pressure setting of at least one safety relief valve connected to any vessel or system cannot be greater than a pressure at the safety relief valves corresponding to the design pressure (1250 psig) anywhere in the protected vessel.*

E. *Valves which are additional to the one(s) set at or below design pressure may be set higher, but in no case do any of these settings exceed a pressure at the safety relief valves corresponding to 105% of the design pressure anywhere in the vessel (1.05 x 1250 psig = 1312.5 psig).*

5A.2.2 AVAILABILITY INDEX

Overpressure protection with valve failure conditions is investigated by the General Electric Company. Valve failure combinations are evaluated with respect to pressure margin criteria which meet the ASME Code requirements. An availability index is derived which expresses the probability that the number of valves which meets the pressure margin criterion will be operational at any future instant of time. This index is a function of:

- *Total number of valves in the system.*
- *Minimum number of valves which satisfies the pressure margin criterion for a MSIV flux scram transient.*
- *Failure rate of the valves.*
- *Testing interval.*

Current General Electric policy has set an availability index (I_A) goal for the overpressure protection system ≥ 0.99999.

5A.3 METHOD OF ANALYSIS

To design the pressure protection for the nuclear boiler system, extensive analytical models representing all essential dynamic characteristics of the system are simulated on a large digital computing facility. These models include:

- *Hydrodynamics of the flow loop.*
- *Reactor kinetics.*
- *Thermal characteristics of the fuel and its transfer of heat to the coolant.*
- *All the principal controller features, such as feedwater flow recirculation flow, reactor water level, pressure, and load demand. (These are represented with all their principal nonlinear features in models that have evolved through extensive experience and favorable comparison of analysis with actual boiling water reactor (BWR) test data.)*

A detailed description of this model is documented in licensing topical report NEDO-10802, "Analytical Methods of Plant Transient Evaluations for the GE-BWR," R. B. Linford. Included within this model are components of the reactor vessel pressure protection system, which is the subject of this report. Dual safety relief valves are simulated in the nonlinear representation, and the model thereby allows full investigation of the various valve response times, valve capacities, and actuation setpoints that are available in applicable hardware systems.

Typical capacity characteristics as modeled are represented in figure 5A-1 for the safety relief valves. The associated bypass, TCV, and MSIV characteristics are also represented in the model.

5A.4 SYSTEM DESIGN

A parametric study was conducted to determine the required steam flow capacity of the safety relief valves, which satisfies the ASME Code requirements and the availability index goals. This study was based on the following assumptions.

5A.4.1 OPERATING CONDITIONS

The following conditions are the most severe because the maximum stored energy exists at these conditions. At lower power conditions, the transients would be less severe.

	HNP-1	*HNP-2*
Operating power (MWt)	*2537 (design power)*	*2533 (104% of reactor warranted power)*
Vessel dome pressure (psig)	*1020*	*1020*
Steam flow (x 10^6 lb/h)	*10.5*	*10.96*

5A.4.2 TRANSIENTS

The overpressure protection system must accommodate the most severe pressurization transient. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirect derived scrams; therefore, it is used as the overpressure protection basis event.

5A.4.3 SCRAM

- *Direct reactor scram - failed.*
- *SCRAM reactivity curve - figure 5A-2 (design basis).*
- *Control rod drive scram motion - figure 5A-2.*

5A.4.4 SAFETY RELIEF VALVE TRANSIENT ANALYSIS SPECIFICATIONS

	HNP-1	*HNP-2*
Valve groups	*One*	*Three*
Pressure setpoint (psig)	*1100 (+ 1% assumed error)*	*1101, 1111, 1121*
Delay time (s)	*0.40*	*0.40*
Stroke time (s)	*0.10*	*0.10*

5A.4.5 SAFETY RELIEF VALVE SIZING

Sizing of the safety relief valve capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1375 psig) in response to a specified transient. General Electric design practice and ASME Code requirements are satisfied with the closure of all MSIVs with scram tripped by a high neutron flux signal as the reference transient. The minimum capacity determined according to the specified criteria is translated into a discrete valve requirement and compared with the total number of valves required to meet the availability index criterion.
The safety relief valve capacity required to provide overpressure protection at all levels of indirect scram is derived from an evaluation of the MSIV pressure scram transient.

5A.4.6 AVAILABILITY INDEX (I_A)

The availability index considers both the minimum number of valves determined from the safety relief valve sizing criteria and the total number of operational valves provided for the plant.

The total number of valves provided for the plant is established from the number of valves required to satisfy the availability index criterion.

5A.5 EVALUATION OF RESULTS

5A.5.1 SAFETY RELIEF VALVE SIZING

The parametric relationship between peak vessel (bottom) pressure and safety relief valve capacity for the MSIV transient with high flux, high pressure, and MSIV position scram is described in figure 5A-3. The safety relief valve sizing requirement, based on MSIV flux scram, is eight valves for HNP-1 and seven valves for HNP-2.

The time response of HNP-1 and HNP-2 vessel pressure to the MSIV transient with both flux and pressure scrams for 11 valves is illustrated in figure 5A-4. The time response of HNP-2 vessel pressure to the MSIV transient with flux scram for 7 valves is also illustrated in figure 5A-4.

5A.5.2 AVAILABILITY INDEX (I_A)

The availability index is based upon the number of safety relief valves required to provide an acceptable margin to the vessel code limit (1375 psig) for the MSIV flux scram transient. The data employed in the derivation of the availability index are outlined as follows:

	HNP-1	HNP-2
Safety relief valves (total installed)	11	11
Safety relief valves (MSIV flux scram)	8	7
Valve failure rate[a] (failures/10^6 operating hours)	1.1	1.1
Testing interval (years)	< 1.666	≤ 2.2
Availability index	> 0.999999	> 0.999999

a. The downtime, or period that the valve would be unavailable for service if it failed, was determined to be dominated by the period between testing. The effects of these differences in downtimes are included in the availability index calculations.

5A.6 SAFETY RELIEF VALVE CHARACTERISTICS

5A.6.1 SCHEMATIC ARRANGEMENT

The schematic arrangement of the safety relief valves is shown in figures 5A-5 and 5A-6.

5A.6.2 PRESSURE DROP IN INLET AND DISCHARGE

Pressure drop on the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures reported above.

Pressure drop with ASME-rated flow in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent back pressure on each safety relief valve from exceeding 40% of the valve inlet pressure, thus ensuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each safety relief valve has its own separate discharge line.

5A.6.3 SAFETY RELIEF VALVE DESCRIPTION

The safety relief valves, which were manufactured by Target Rock to ASME Code Section III, 1968 with Winter 1968 Addenda, comply with ASME Code Section III, Paragraph N9ll.4(a)(1), for pilot-operated valves. Quantities and setpoints are as follows:

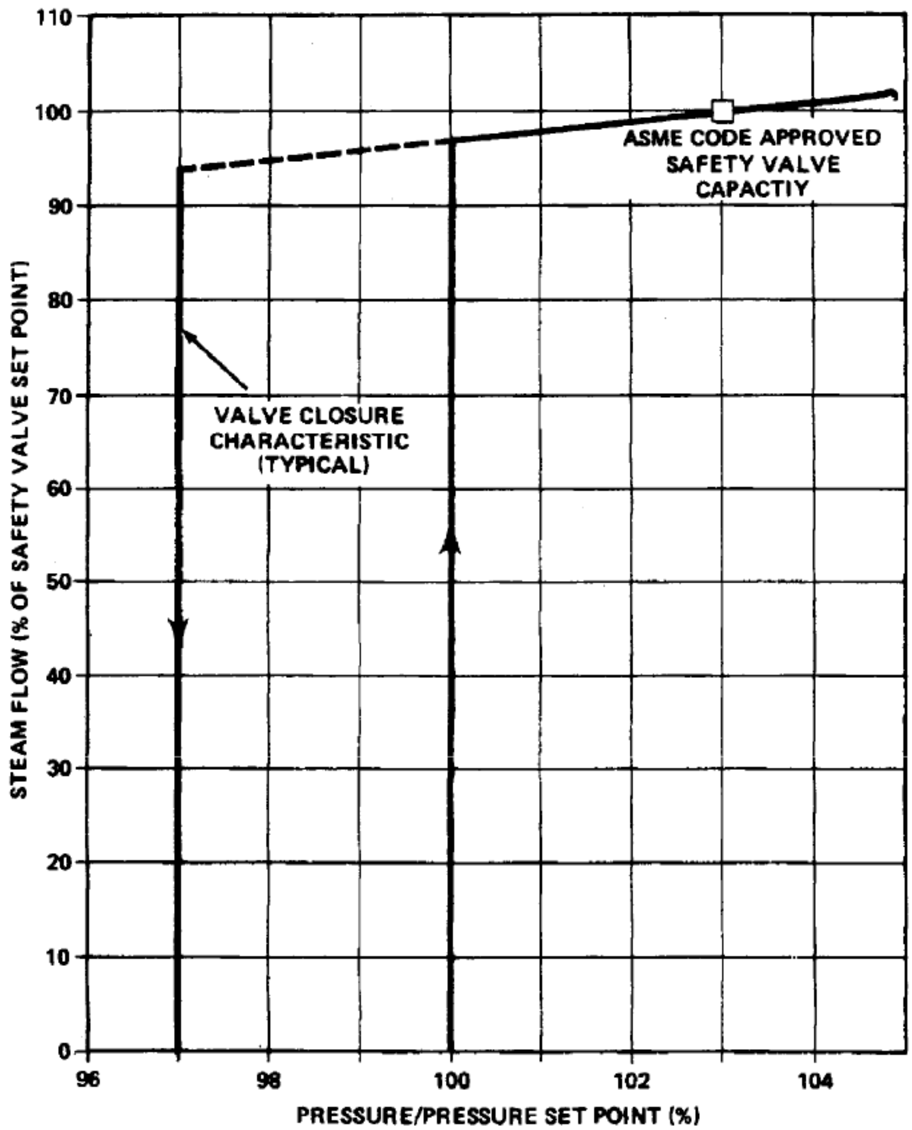
	Setpoint (psig)[a]		ASME Rated Capacity at 103% of Set Pressure (lb/h minimum)	
Quality	HNP-1	HNP-2	HNP-1	HNP-2
4	1080	1090	788,400	869,000
4	1090	1100	794,400	876,800
3	1100	1110	803,400	884,700

a. This column reflects the nominal safety relief valve set pressure used in the original overpressure analysis. Current setpoints are listed in HNP-1 table 4.4-1 and HNP-2 table 5.2-4.

5A.7 CONCLUSION

Safety requirements have long demanded very high reliability in the reactor functions. Recognition of this reliability as being completely adequate justification for these functions to contribute to vessel pressure protection is reflected in the Section III ASME Code provisions. Actual General Electric design practice very conservatively applies the code provisions which result in margins even beyond those necessary to satisfy code limits which further enhance the reliability of vessel pressure protection.

This design basis for sizing safety relief valves with indirect credit is technically sound and a most realistic approach. It is allowed under Section III of the ASME Boiler and Pressure Vessel Code which has been adopted by the General Electric Company in the design of HNP-1 and HNP-2 BWRs.



ACAD 25A01

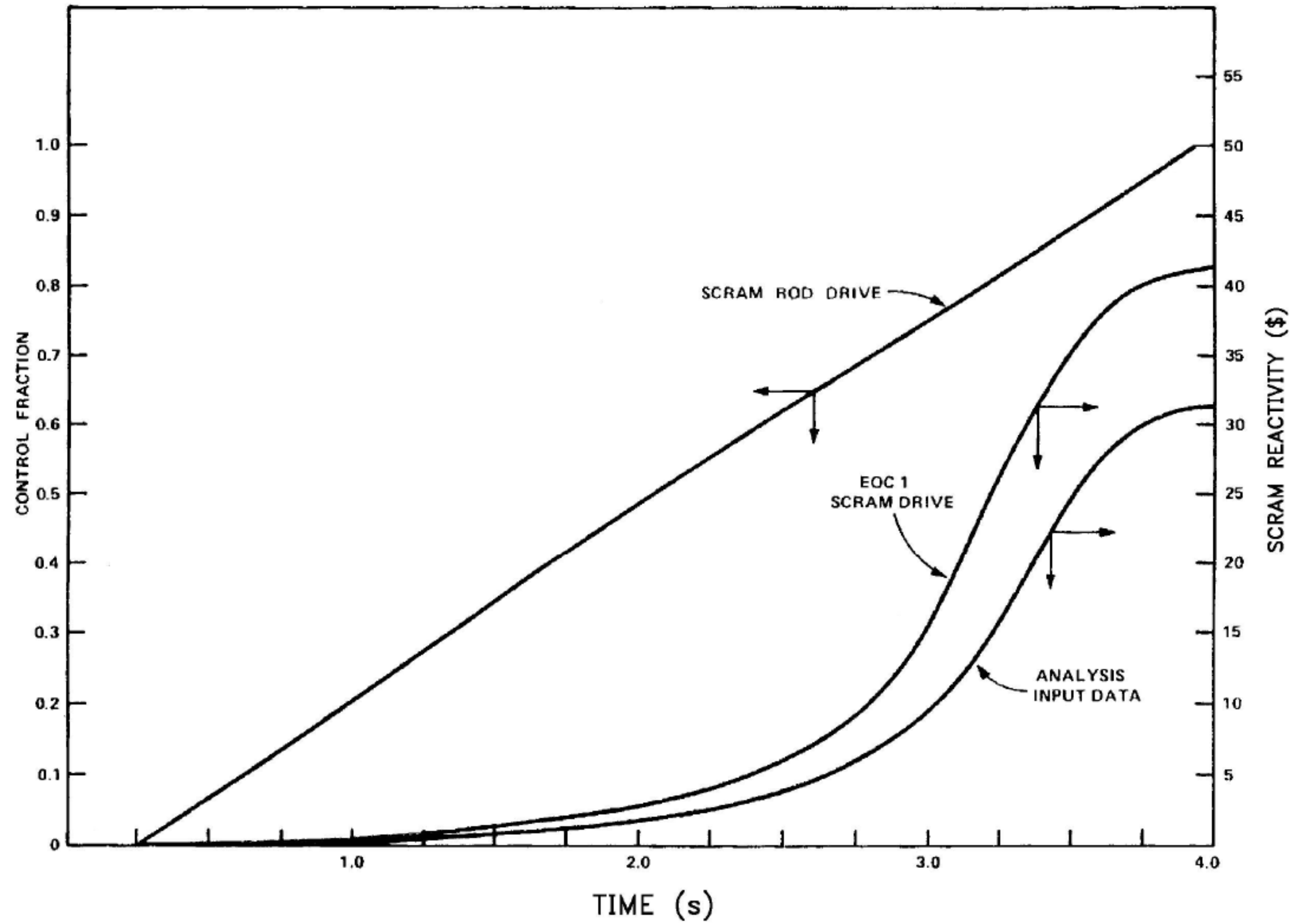
HISTORICAL

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL DUAL SAFETY RELIEF VALVE CAPACITY CHARACTERISTICS

FIGURE 5A-1



ACAD 15A021

HISTORICAL

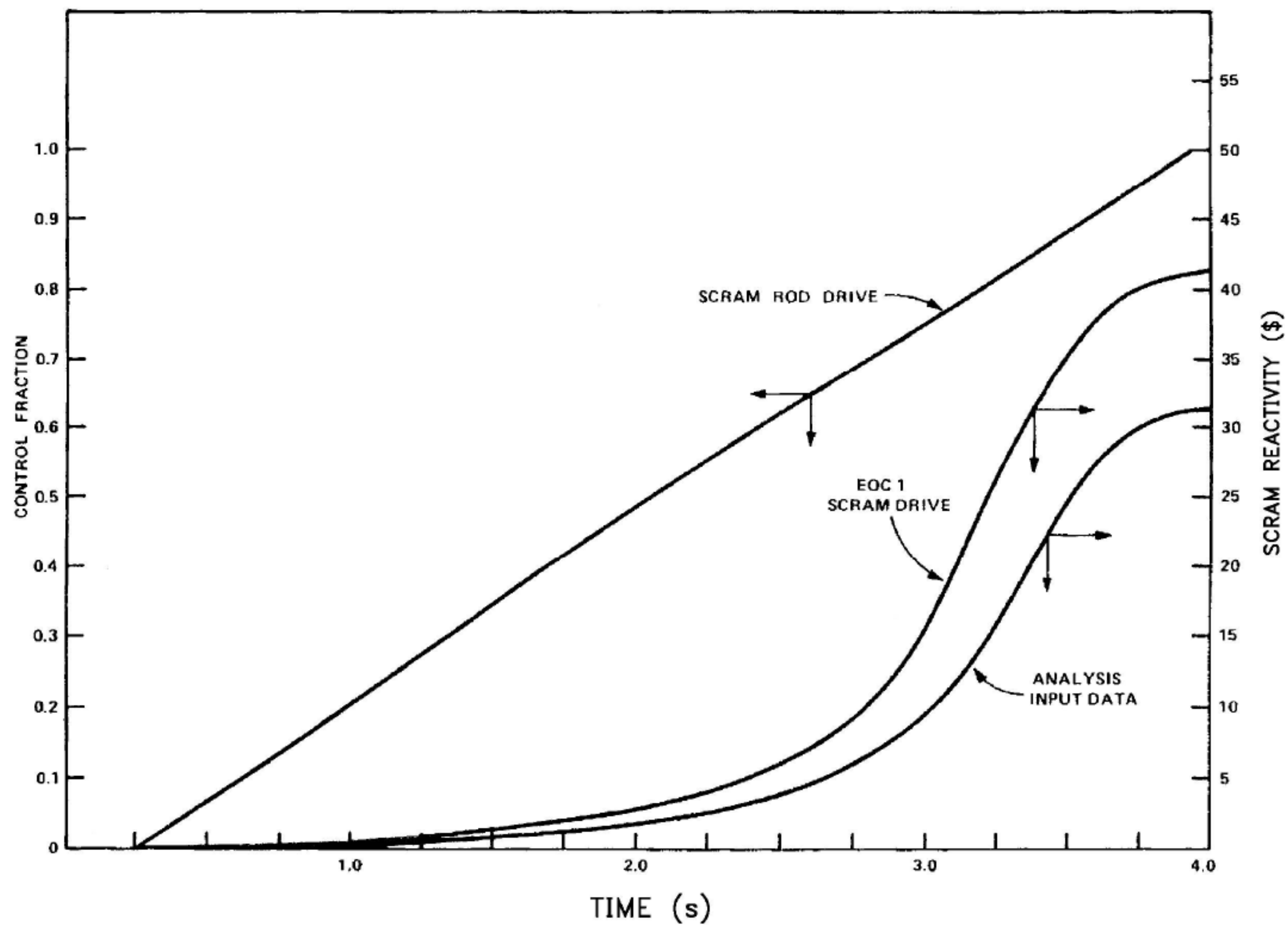
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

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

SCRAM ROD DRIVE AND SCRAM REACTIVITY VS TIME

FIGURE 5A-2 (SHEET 1 OF 2)



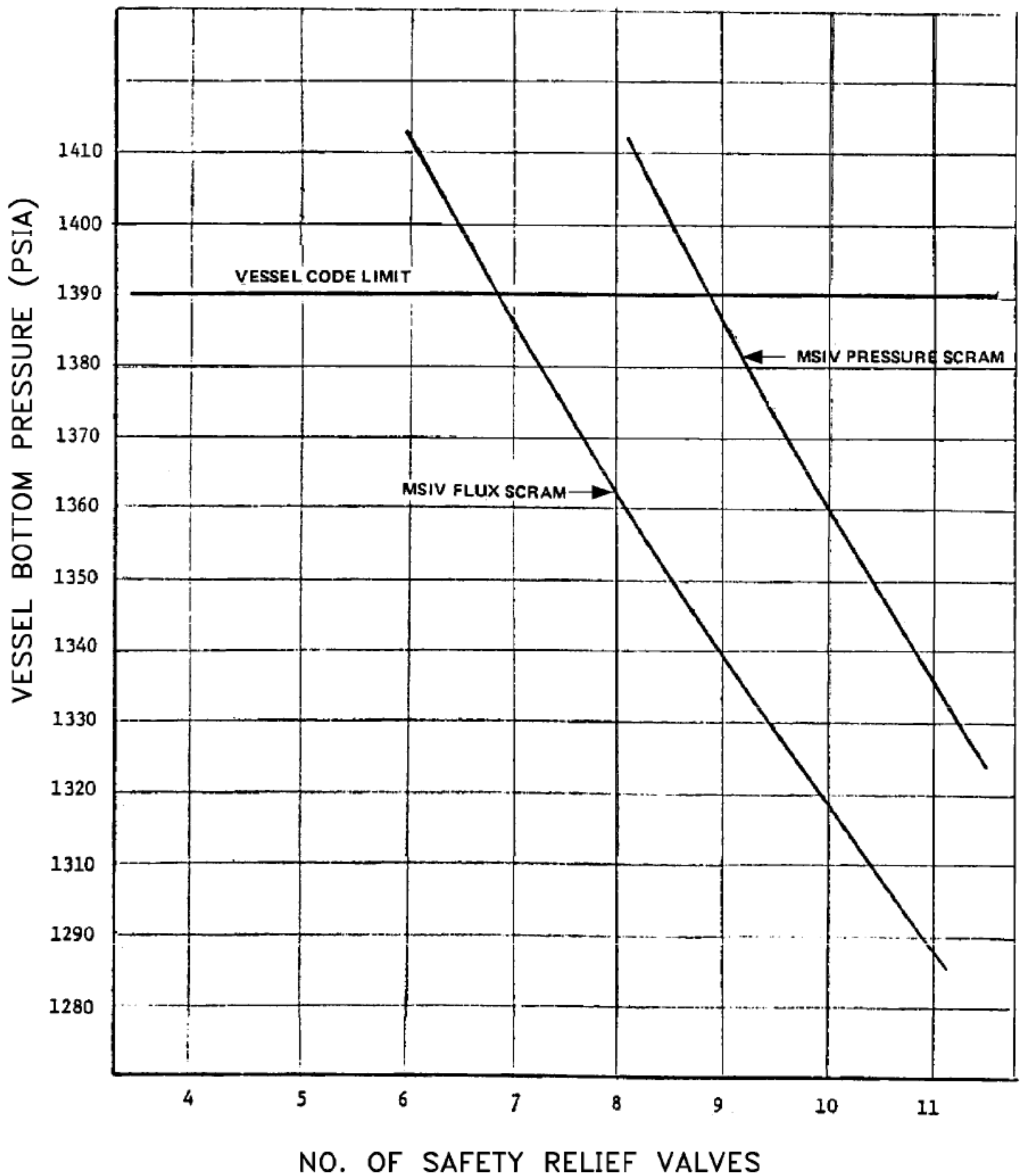
ACAD 25A022

HISTORICAL
REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCRAM ROD DRIVE AND SCRAM REACTIVITY VS TIME

FIGURE 5A-2 (SHEET 2 OF 2)



ACAD 15A031

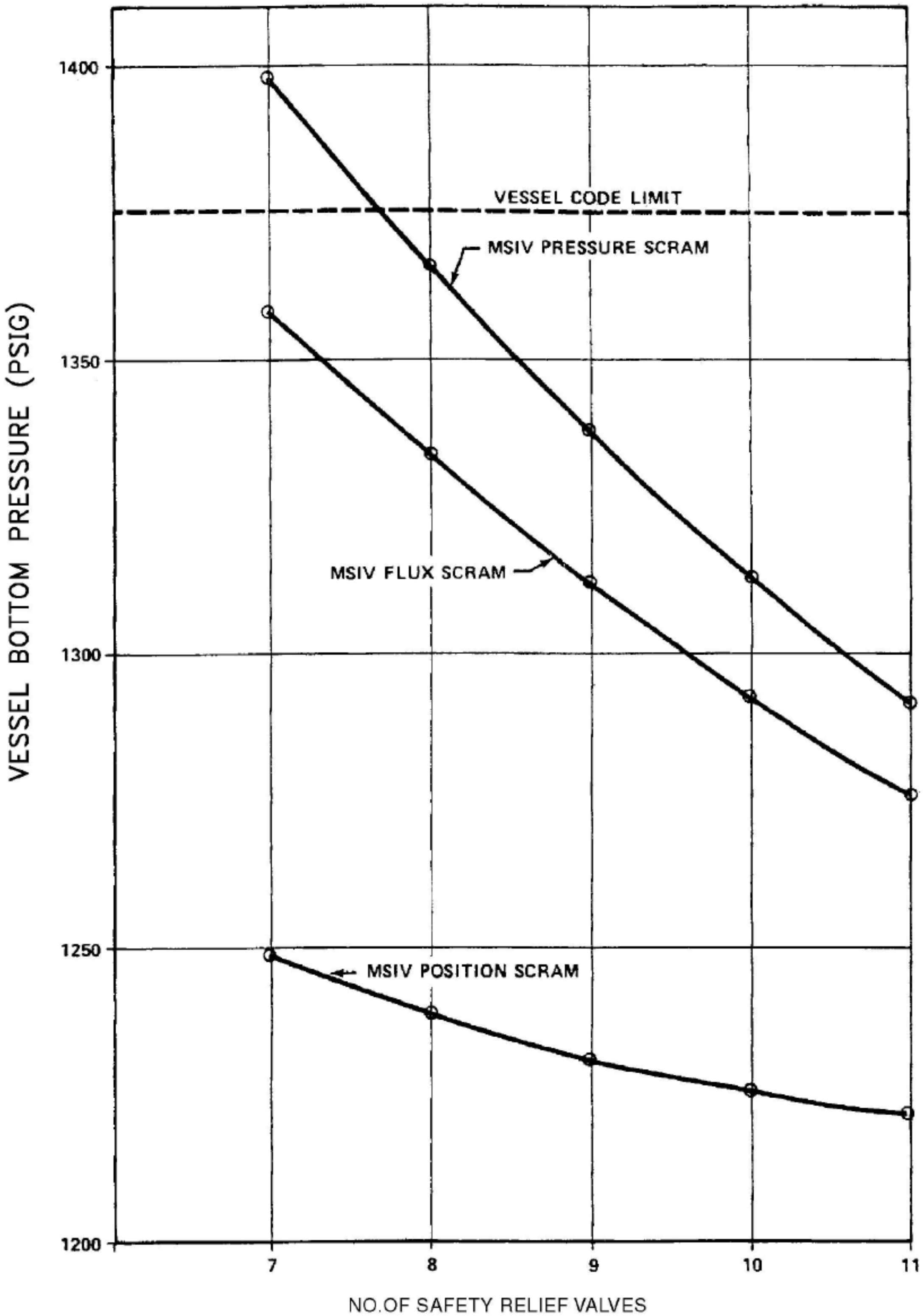
HISTORICAL

REV 19 7/01

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

PEAK VESSEL BOTTOM PRESSURE VS SAFETY RELIEF VALVE CAPACITY

FIGURE 5A-3 (SHEET 1 OF 2)



ACAD 25A032

HISTORICAL

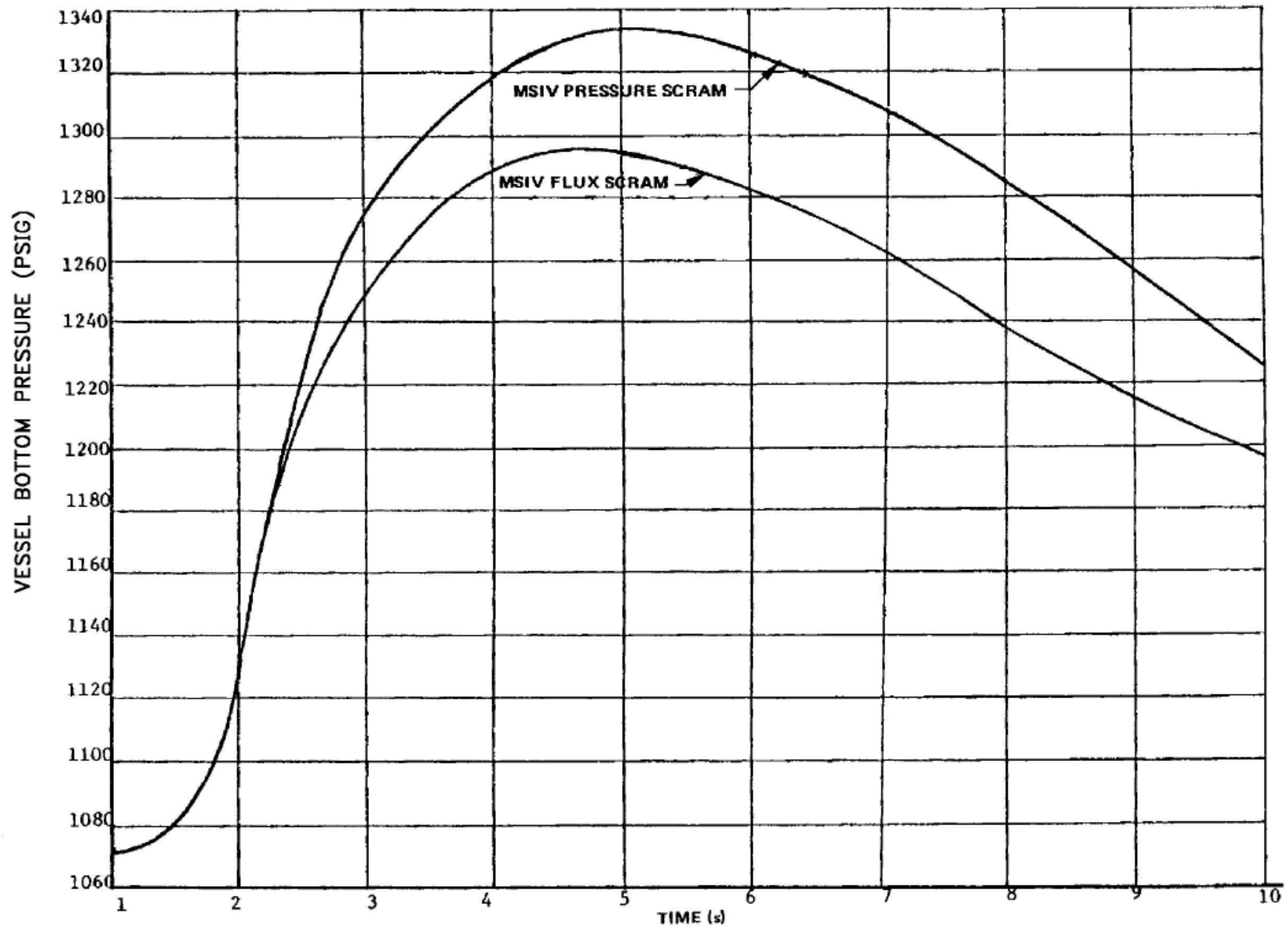
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

PEAK VESSEL BOTTOM PRESSURE VS SAFETY RELIEF VALVE CAPACITY

FIGURE 5A-3 (SHEET 2 OF 2)



ACAD 15A041

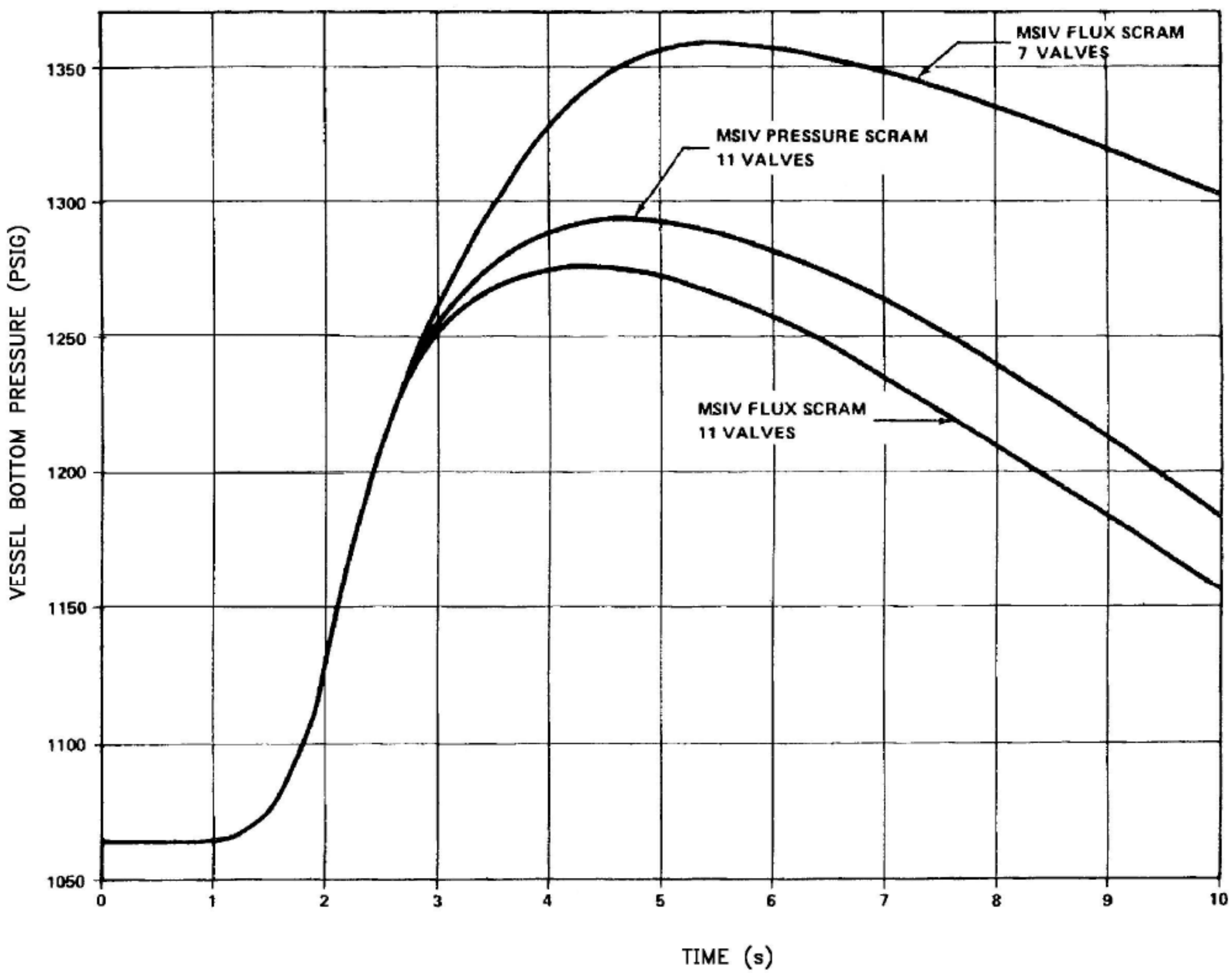
HISTORICAL
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

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

TIME RESPONSE OF MSIV TRANSIENTS

FIGURE 5A-4 (SHEET 1 OF 2)



HISTORICAL

REV 19 7/01

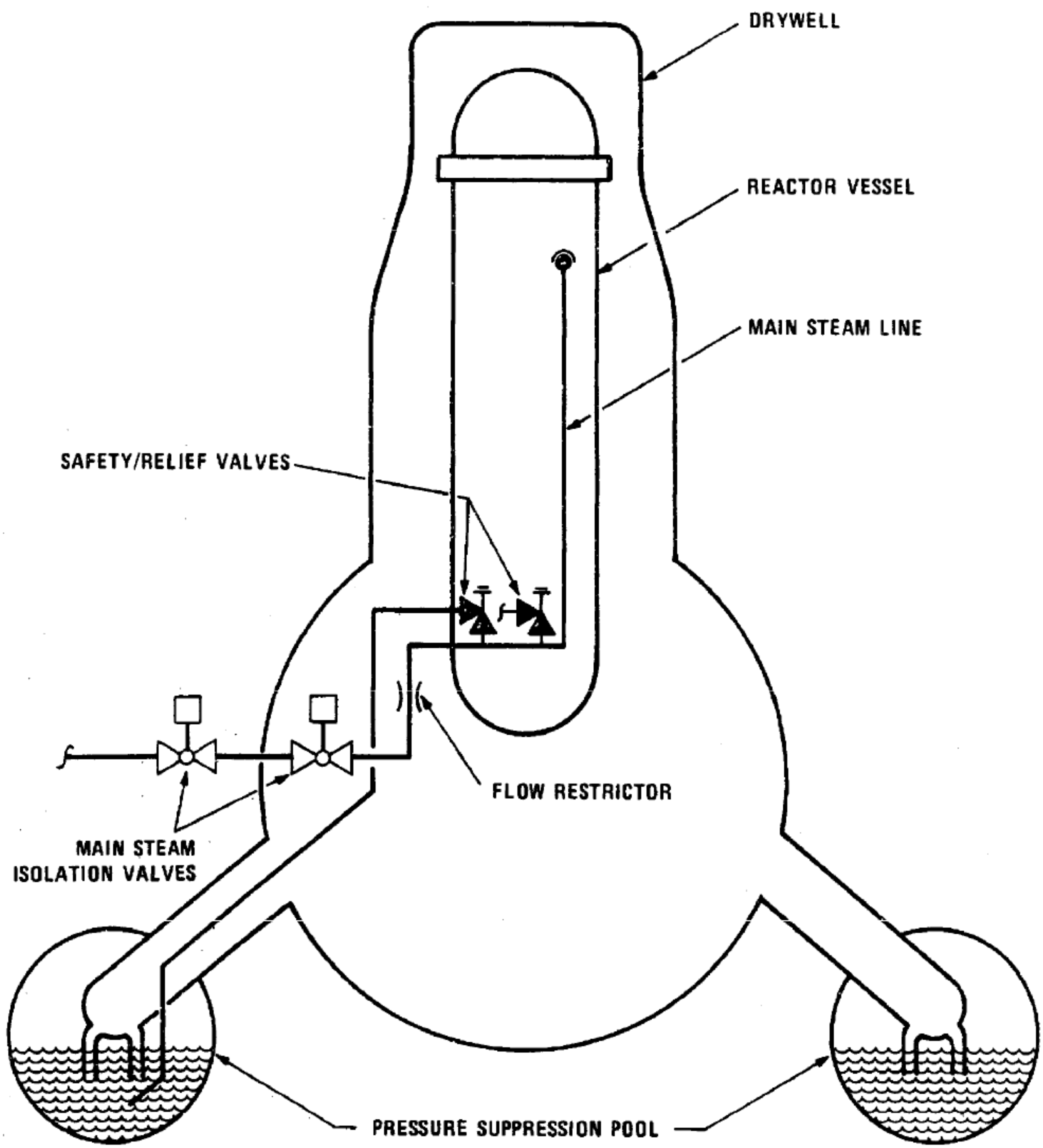
ACAD 25A042

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIME RESPONSE OF MSIV TRANSIENTS

FIGURE 5A-4 (SHEET 2 OF 2)



ACAD 25A05

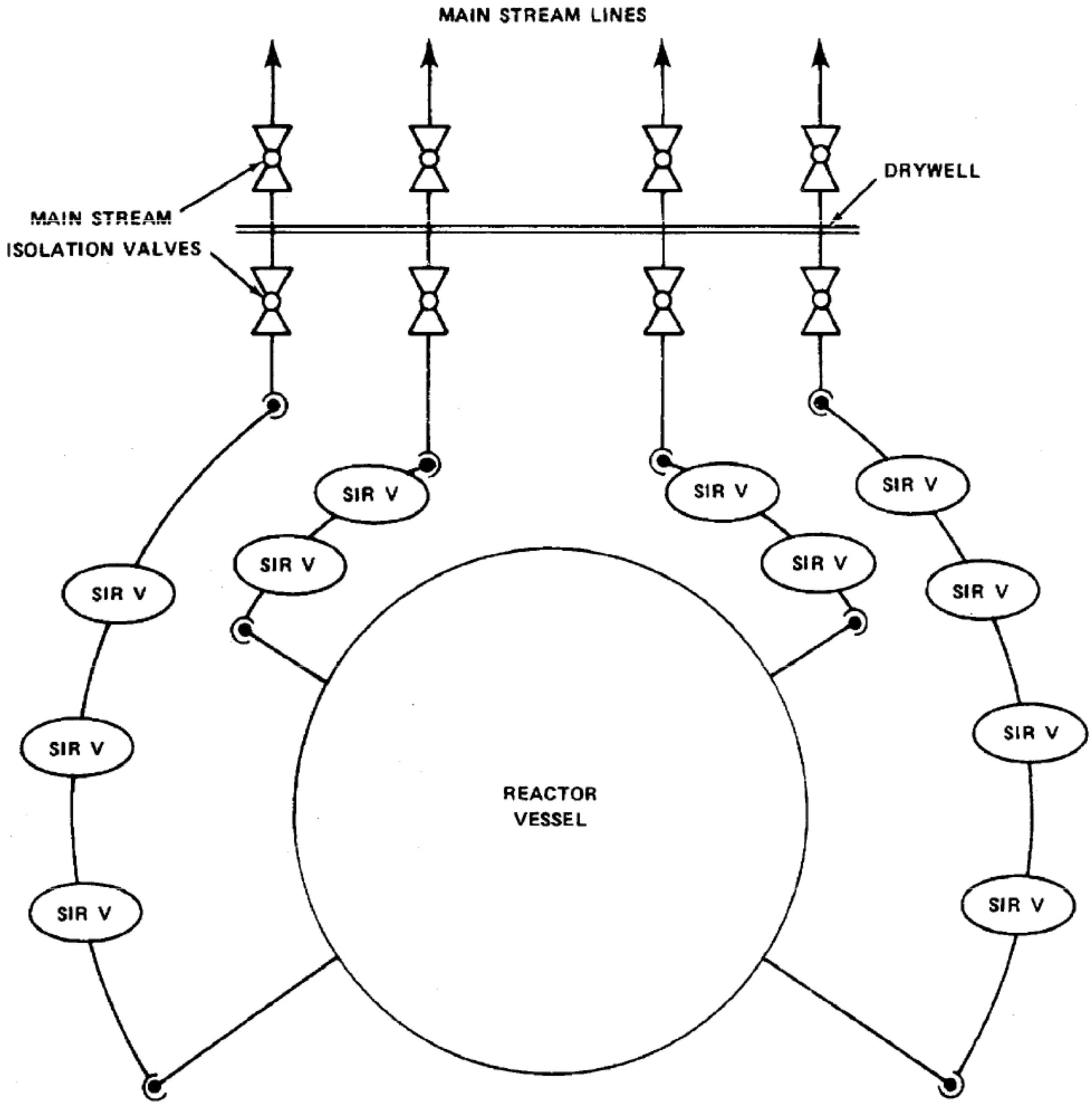
HISTORICAL
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC ELEVATION

FIGURE 5A-5



ACAD 25A06

HISTORICAL

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC PLAN

FIGURE 5A-6

6.0 ENGINEERED SAFETY FEATURES

6.1 GENERAL

Engineered safety features (ESFs) mitigate the consequences of postulated accidents, the occurrence of which is very unlikely. The following ESFs and containment atmospheric dilution (CAD) (not an ESF but important to safety), are discussed in this chapter:

A. Containment Systems

1. Containment Heat Removal

   The containment heat removal system consists of the shutdown cooling and the suppression pool cooling modes of the residual heat removal (RHR) system for planned and abnormal operation, as well as the core spray (CS) system and the low-pressure coolant injection (LPCI) mode of RHR for accident mitigation. Heat absorbed in these cooling modes is exchanged to the residual heat removal service water (RHRSW) system via the RHR heat exchangers.

2. Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident (LOCA)

   The CAD system, a subsystem to the primary containment purge and inerting system, is used to control the concentration of hydrogen and oxygen that may be generated in the drywell and torus following a postulated LOCA. The CAD system controls the combustible gases within the containment by diluting the combustible gases. Thus, the combustible gases remain below their flammability limit.

3. Containment Isolation

   The containment isolation system isolates the lines that could become a leakage path for radioactivity past the containment barrier during abnormal conditions within the containment.

B. Emergency Core Cooling System (ECCS)

The ECCS is comprised of integrated subsystems that provide cooling water to the reactor pressure vessel (RPV) to compensate for the loss of normal coolant under either postulated accident or anticipated operational occurrence conditions. The subsystems comprising the ECCS are as follows:

1. High-Pressure Coolant Injection (HPCI)

   The HPCI system is designed to pump water into the RPV over a wide range of pressures. For small breaks that do not result in rapid RPV

depressurization, the system maintains RPV water level and depressurizes the RPV until RPV pressure is below the pressure at which either LPCI or the CS system operation can maintain core cooling.

2. Automatic Depressurization

   The automatic depressurization system (ADS) employs safety-relief valves (SRVs) to reduce the RPV pressure to the operating range of LPCI and the CS system for events in which the HPCI system is unable to maintain RPV water level.

3. CS

   The CS system automatically sprays water onto the top of the fuel assemblies to cool the core in the event of a large break. The protection extends to a small break in which the HPCI system cannot maintain RPV water level, and as a result, the ADS operates to lower RPV pressure so LPCI and the CS system can provide core cooling.

4. LPCI Mode of RHR

   Like the CS system, LPCI is designed to protect the core against large breaks. The protection is extended to small breaks in which the HPCI system cannot maintain RPV water level, and as a result, the ADS operates to lower RPV pressure so LPCI and the CS system can provide core cooling.

C. Standby Gas Treatment

   The standby gas treatment system is an air purification system that removes potentially radioactive material from the primary and secondary containments in the event of certain postulated design basis accidents (DBAs).

D. Main Control Room Environmental Control (MCREC)

   The objective of the MCREC system is to ensure control room personnel are adequately protected against any release of radiation following a postulated DBA.

In addition to the ESFs discussed in this chapter, ESF systems discussed in other FSAR chapters limit the consequences of postulated accidents. Table 6.1-1 provides the references to the other FSAR sections, subsections, and paragraphs.

TABLE 6.1-1

ESFs DISCUSSED IN OTHER FSAR CHAPTERS

ESFs	FSAR Reference
Control rod velocity limiter	1.2.7.14, 4.2.3.1, 15.2, 15.3, and 15C.4
Control rod drive housing supports	1.2.7.15, 4.5, and 4.2.4.7
Main steam line flow restrictors	5.5.4 and 7.7.3
Main steam line isolation valves	5.5.5, 6.2, 7.3, 7.4, 7.2.2, and 15.4
Low-low set relief logic system	5.5.17, 7.1.1, 7.4.4, and 7.8
Reactor protection system	7.2
Analog transmitter trip system	7.8

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Safety Design Bases

The containment systems are designed to:

- Withstand the postulated bounding peak transient pressures and temperatures resulting from a design basis accident (DBA); i.e., a mechanical failure of the reactor primary system equivalent to the circumferential rupture of one of the recirculation lines as specified in paragraph 6.2.3.1.

- Accommodate the effects of metal-water reactions and other chemical reactions following the postulated DBA, consistent with the performance objectives of the emergency core cooling system (ECCS).

- Maintain indefinite functional integrity following the postulated DBA.

- Permit filling the reactor pressure vessel (RPV) with water to a level above the reactor core.

- Protect against missiles from internal or external sources and excessive motion of pipes that could directly or indirectly endanger the integrity of the containment.

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

- Limit leakage during and following the postulated DBA to values less than leakage rates that result in offsite doses greater than the guideline dose values of Title 10 Code of Federal Regulations (CFR) Part 50.67.

- Provide the capability to conduct periodic leakage tests to confirm the integrity of the containment at calculated peak pressure resulting from the postulated DBA.

- Direct the flow from postulated pipe ruptures to the suppression pool, distribute such flow uniformly throughout the pool, and condense the steam portion of the flow rapidly.

- Limit the differential pressures (ΔPs) between the drywell and the suppression pool during the various post-accident cooling modes.

- Rapidly close and isolate all pipes or ducts that penetrate the containment by providing a containment barrier sufficient to maintain leakage within permissible limits.

- Withstand the peak environment transient pressures and temperatures due to a postulated small line break.

During the DBA, with the minimum ECCS pumps operating and the available service water at the design maximum temperature, the long-term peak pool temperature does not exceed the design temperature.

6.2.1.2 <u>System Description</u>

The two passive provisions for containment of possible post-accident airborne contamination are the primary containment system and the secondary containment system. Both the primary containment and the secondary containment can be vented through the standby gas treatment system (SGTS) to ensure the SGTS filters any accident-related discharge before release. The SGTS is discussed in subsection 6.2.4.

6.2.1.2.1 Primary Containment

The design of the primary containment is provided in subsection 3.8.2.

In the event of a process system piping failure within the drywell, RPV water and steam are released into the drywell. The resulting increased drywell pressure forces a mixture of air, steam, and water through the vents into the pool of water stored in the suppression chamber. The steam condenses in the suppression pool, resulting in a rapid pressure reduction in the drywell. Noncondensible gases transferred to the suppression chamber pressurize the chamber and are subsequently vented back to the drywell through the vacuum breaker valves to equalize the pressure between the two vessels. The containment cooling and spray modes of the residual heat removal (RHR) system provide continuous cooling of the primary containment under accident conditions, as discussed in subsection 6.2.2. Appropriate isolation valves are actuated to ensure containment of radioactive material that might otherwise be released from the primary containment.

Important design parameters of the primary containment are provided in table 6.2-1. Important features of the primary containment system are described in the following paragraphs.

6.2.1.2.1.1 **<u>Drywell</u>.** The design of the drywell is provided in paragraph 3.8.2.1.1.

6.2.1.2.1.2 **<u>Suppression Pool/Torus</u>.** The design of the suppression pool is provided in paragraph 3.8.2.1.2. The suppression pool contains a maximum of 90,550 ft^3 of water and has a minimum net airspace above the pool of ~ 109,712 ft^3. The torus is held on supports that transmit vertical and seismic loadings to the reinforced concrete foundation slab of the reactor building. Space for inspection and maintenance is provided outside the pool.

The suppression pool is designed for 56 psig and to the same material and code requirements as the steel drywell vessel. All materials have an initial nil ductility transition temperature (NDTT) of ~ 0°F.

6.2.1.2.1.3 **Vent System.** The design of the vent system is provided in paragraph 3.8.2.1.2. The vent pipes are designed for an internal pressure of 56 psig at 281°F (Unit 1) and 340°F (Unit 2), are fabricated of SA-516 GR70 steel plate, and comply with requirements of the American Society of Mechanical Engineers (ASME) Code, Section III, Subsection NE.

Vacuum breakers discharge from the suppression chamber into the vent header system. Vacuum breaker sizing is based upon the Bodega Bay test configuration.(1)

Both the drywell and the suppression chamber can be vented to the atmosphere through the SGTS.

6.2.1.2.1.4 **Penetrations.** The design of the general types of penetrations is provided in paragraph 3.8.2.1.4. Primary containment penetrations are designed for peak transient pressures expected during a loss-of-coolant accident (LOCA). The penetrations either withstand or are shielded from the forces caused by impingement of fluid from the rupture of the largest local pipe or connection.

The penetrations are designed to accommodate without failure any combination of thermal and mechanical stresses that can be encountered during all modes of operation.

6.2.1.2.1.5 **Personnel and Equipment Access Locks.** The design of personnel and equipment access locks is provided in paragraph 3.8.2.1.3.

6.2.1.2.1.6 **Vacuum Relief Valves.** The containment vacuum relief valves consist of the suppression chamber-to-drywell vacuum breaker valves and the reactor building-to-suppression chamber vacuum breaker valves. The primary containment vacuum relief valves are designed to maintain an external pressure of not more than 2 psi greater than the concurrent internal pressure. The vacuum relief system, as shown on drawing no. H-26084, is of adequate size to prevent a pressure collapse in either the drywell or the torus as a result of the most rapid cooldown transient that can occur during normal operation or a postulated accident condition assuming the failure of a single active component. The primary containment is capable of withstanding an external ΔP of > 2 psi without experiencing structural failure or loss of leaktightness, or exceeding the yield stress.

6.2.1.2.1.6.1 **Suppression Chamber-to-Drywell Vacuum Breakers.** Vacuum in the drywell is relieved by 12 valves located on the vent header of the vent system between the drywell and the suppression chamber. These valves are self-actuating vacuum breakers similar to simple check valves that can be remotely operated for testing purposes. The position-indicating system associated with each of these valves complies with Institute of Electrical and Electronics

Engineers (IEEE) 279 in that each valve has two independent, closed indication limit switches and one open indication limit switch installed to ensure physical separation. The closed indication limit switches are actuated by the valve disc and are installed at opposite sides of the disc. The open indication limit switch is actuated by the disc linkage and is installed at the top of the valve disc. Each closed indication limit switch is powered from separate power sources, and the wiring for each switch is routed in separate raceway systems.

Figure 6.2-1 is a sketch of an HNP-2 suppression chamber-to-drywell vacuum breaker. Each vacuum breaker discharges into the vent header through a short, straight run of 18-in. diameter, schedule 80-carbon steel pipe.

The suppression chamber and drywell vacuum relief valves are designed and manufactured in accordance with the requirements of ASME Code, Section III, Class 2. The valves and operators are Seismic Category 1 qualified.

The vacuum breakers are the balanced, self-activating type with an air operator provided to exercise the valve from the main control room (MCR). Three limit switches provide position indication: two limit switches for the closed position and one limit switch for the open position. The valves are designed to operate at containment pressures up to 62 psig, with an ambient temperature in the range of 30°F to 350°F. The valves open fully within 1 s with a 0.5-psi ΔP existing across the valve.

Vacuum breaker position indication is provided on local panel 2T48-P001 and MCR panel 2H11-P602. No annunciators are provided. Physical and electrical separation is maintained for electrical circuits extending from the valves to the MCR. Each indicating light is the push-to-test type.

The vacuum breaker limit switch design employs permanent magnets to control mechanical contacts, providing valve position indication. The vacuum breakers use a magnetic latch for positive closing. Therefore, upon reaching the setpoint, the snap action of the latch results in an instantaneous NOT CLOSED indication.

The limit switches are not required to meet the environmental qualification requirement of 10 CFR 50.49.

Based upon the Bodega Bay pressure-suppression tests,[1] the total cross-sectional area of the main vent system between the suppression chamber and the drywell was established at a minimum of 51.5 times the total break area.

The vacuum relief capacity between the suppression chamber and the drywell should be no $< \sim$ 1/16 of the total main vent cross-sectional area.

6.2.1.2.1.6.2 Reactor Building-to-Suppression Chamber Vacuum Breakers. Vacuum in the suppression chamber is relieved by a vacuum breaker and an air-operated butterfly valve located in each of two lines from the reactor building to the suppression chamber. Differential pressure actuates the butterfly valve. The vacuum breaker is self actuating and can be remotely operated for testing purposes.

The reactor building-to-suppression chamber vacuum breakers are sized on the basis of the flow of air from the secondary containment required to limit the maximum negative containment (drywell and torus) pressure to within design limits. The maximum depressurization rate is a function of the containment spray flowrate and temperature, and the assumed initial conditions of the containment atmosphere. Low-spray temperatures and atmospheric conditions that yield the minimum number of contained noncondensible moles of gas (air or nitrogen) are assumed for conservatism.

6.2.1.2.1.7 **Primary Containment Cooling System.** The primary containment (drywell) cooling system is discussed in subsection 9.4.6.

6.2.1.2.1.8 **Primary Containment Purge System.** The primary containment is vented during reactor heatup, as necessary, to eliminate a pressure buildup and can be periodically vented thereafter to maintain pressure within operating limits during planned operations. The drywell and the suppression chamber can be vented separately. Venting is accomplished by drawing the primary containment atmosphere through the SGTS where the gases are stripped of their particulate and halogen contents, and released via the main stack.

Clean reactor building air is supplied to the suppression pool and the drywell for purge and ventilation purposes during reactor shutdown and refueling periods to permit personnel access and occupancy. The ventilation lines supplying air to the primary containment are provided with two fast-acting pneumatic cylinder-operated butterfly valves in series for isolation purposes. These valves are normally closed during plant operation but may be opened within 24 h of reaching < 15% of rated thermal power (RTP) for fast venting. Outboard isolation valves 2T48-F308 and 2T48-F324 are provided with an interlock permissive that will not allow opening unless purge fan 2T48-C003 is energized.

Following the DBA, venting is accomplished by drawing the primary containment atmosphere through a flow-controlled valve and the SGTS to the main stack.

Purge lines are 18 in. and 20 in. in diameter, and vent lines are 18 in. in diameter. The isolation valves on the 18-in. vent lines have 2-in. bypass lines around them for use during normal reactor operation. Two additional and redundant excess flow isolation dampers are provided on the vent line upstream of the SGTS filter trains. These isolation dampers, together with the containment isolation valves, prevent high LOCA pressure from reaching the SGTS filter trains in the unlikely event a LOCA occurs during venting. To ensure a vent path is available, a 2-in. bypass line is provided around the dampers.

In accordance with the requirements of NRC Generic Letter 89-16, “Installation of a Hardened Wetwell Vent,” venting the torus in the event of a loss of long-term decay heat removal sequence can be accomplished by bypassing the low pressure SGTS filter trains. This vent capability can be utilized for severe accident situations and is not intended for normal operation or design basis accident mitigation.

During the drywell heatup that accompanies power ascension, the vent bypass lines are opened periodically to maintain a constant drywell pressure while compensating for containment air volume temperature increases.

The Technical Specifications require primary containment operability in Modes 1, 2, and 3. Access to the primary containment during reactor power operation is not normally permissible. The purge system is not used during normal reactor operation to reduce airborne activity in the primary containment.

Containment vent line effluents are directed to the SGTS for processing prior to release through the main stack. The purge lines open to the secondary containment volume processed by the SGTS.

The evaluation of compliance with Branch Technical Position (BTP) CSB6-4 is as follows:

A. The operability of the isolation valves is provided in paragraph 3.9.2.4. The design basis for the valves and operators includes the higher post-LOCA pressures.

B. The large purge and vent lines are typically closed during normal operation. However, in accordance with the Technical Specifications, purging may commence within 24 h of the unit reaching < 15% RTP for fast drywell venting. Only one 2-in. bypass vent line is used, when necessary, to correct for pressure rise due to a rise in the temperature during increasing power levels. Once the power level stabilizes and the containment air volume reaches an equilibrium temperature, the bypass vent line is closed.

C. The purge and vent lines typically used during cold shutdown and refueling are 18 in. and 20 in. The vent lines typically used during normal reactor operation are 2 in. in diameter.

D. The containment isolation provisions for the purge and vent lines meet all standards appropriate to engineered safety features (ESFs).

E. Two isolation valves are on each line. One valve receives an isolation signal from scheme A and the other from scheme B. All isolation valves are fail-close valves.

F. The purge and vent system isolation valve closure times are provided in the HNP-2 Pump and Valve Inservice Testing Program.

G. Seismic Category I debris screens are installed where the 18-in. purge and vent lines enter the drywell.

H. The purge system is not relied upon for temperature and humidity control. The 2-in. bypass vent lines are used for pressure control in the drywell and the torus during plant heatup. Containment environmental control is described in subsection 9.4.6.

I. No containment atmosphere cleanup systems internal to the containment are provided.

J. Provision is made for testing the availability of the isolation function in accordance with the Technical Specifications. Leakage rate tests are performed on individual isolation valves during outages in accordance with the surveillance program.

K. The radiological effects of containment purging have not been analyzed, because the purge and vent lines are always closed and the bypass vent lines, which are normally closed, are operated only during plant heatup periods.

The primary containment purge system is shown schematically on drawing no. H-26084.

6.2.1.2.1.9 Safety Relief Valve (SRV) Lift Analysis Criteria. The SRV discharge pipe connects the SRV to the suppression pool. Under normal circumstances, the discharge end of the pipe is under water and the remainder of the pipe is filled with air. The water may be drawn up into the pipe if the air is at less than atmospheric pressure. When the valve is opened, the transient fluid flow causes time-dependent forces to develop in the pipe wall. The SRVs discharge through an enclosed piping system that carries the steam to the suppression pool. Under conditions of steady-state flow, the forces associated with the flow acting on the piping system are self-equilibrated and do not create bending moments in the piping system. The SRVs discharging into an enclosed piping system create momentary imbalanced forces acting on the piping system during the first few milliseconds following SRV lift. The pressure waves traveling through the piping system following the relatively rapid opening of the SRV cause the SRV discharge piping to vibrate.

The forces and moments acting on the piping system resulting from this vibration must be combined with the results produced by other loading combinations to complete the resultant stresses.

To develop the loads resulting from SRV discharge, the valve-opening characteristics are used, since the forces acting on the piping system when the valve opens are caused by increasing momentum as the steam flow increases from 0 to 100%.

Prior to the lifting of an SRV, the downstream discharge piping is essentially full of air at drywell pressure and temperature conditions. The discharge piping terminates at some predetermined submerged depth in the suppression pool with the water level inside the pipe at approximately the same level as the water level in the torus. Slight variations are possible due to minor pressure differences within the drywell.

When an SRV lifts, the effluent reactor steam causes a rapid pressure buildup in the discharge pipe, causing a rapid compression of the column of air initially occupying the pipe and a subsequent acceleration of the water slug in the submerged position of the pipe. During this blowout process, the pressure in the pipe builds to a peak as the last of the water is expelled.

Forces on the discharge piping system are produced immediately after the SRV lifts due to fluid momentum changes at each elbow, shear forces between the flowing fluid and the pipe wall, and changes in pressure from one elbow to the next. All three contributions vary with time and position along the discharge pipe because:

- The flowrate through the SRV is a function of time.
- The average pressure in the pipe increases until the water slug is cleared.
- Compression and decompression waves, across which significant pressure and velocity changes occur, travel at near sonic speeds between the SRV and the submerged end, dying out only after the water slug is discharged.

A momentum change force is exerted on the discharge piping during the first few milliseconds when the SRV starts to open and prior to the time steady-state flow is established. A fluid transient load is exerted on the SRV and respective piping during the first few milliseconds when the valve is opening and prior to the time steady-state flow is established. With steady-state-flow, the dynamic flow reaction forces are self-equilibrated in the SRV discharge piping. Forces are produced on the discharge piping system immediately after the SRV lifts, due to fluid momentum changes at each elbow. These forces vary with time and position along the discharge pipe because the flowrate through the SRV is a function of time.

The dynamic analysis of the main steam and the SRV discharge piping systems for SRV operation is performed using the response history analysis by direct integration method of the SAP4 (structural analysis program) computer program.

Boundary conditions must be specified for the fluid-forcing function for both the entrance and the exit of the discharge pipe. Submergence of the discharge pipe in the suppression pool controls the entrance conditions.

The valve boundary condition is based upon the ramp-flat steam flow characteristic shown on figure 6.2-2. Mass and energy storage between the RPV and the discharge pipe entrance is negligible due to a relatively small volume associated with the valve. Therefore, entrance properties are obtained from mass and energy conservation in the form:

$$\dot{m} = A\rho_E V_E = \begin{cases} \dot{m}_\infty \cdot \dfrac{t}{t_V}; & t < t_V \\ \dot{m}_\infty ; & t \geq t_V \end{cases} \qquad (1)$$

$$h_O = h_E + \frac{V_E^2}{2g_c} \qquad (2)$$

where:

$$h_E = \frac{k}{k-1} \frac{P_E}{\rho_E} \text{ entrance} \tag{3}$$

$$h_O = \frac{k}{k-1} \frac{P_O}{\rho_O} \text{ stagnation} \tag{4}$$

The last four equations can be combined to relate the discharge pipe entrance pressure and velocity:

$$P_E = \frac{\dot{m}}{A} \left(\frac{P_O}{\rho_O} \frac{1}{V_E} - \frac{k-1}{k} \frac{V_E}{2g_c} \right) \tag{5}$$

Equation 5 generally is solved with equations for a leftward traveling wave at the entrance to obtain P_E and V_E at any time. However, as the valve flowrate increases, the entrance properties may become supersonic and, therefore, completely specified by valve properties. This situation is readily handled by the following consideration:

Critical flow generally occurs in the valve throat. If the valve is treated as an ideal nozzle, throat velocity is given by:

$$V_t^2 = C^2 = k\, g_c \frac{2}{k+1} \frac{P_O}{\rho_O} \tag{6}$$

Furthermore, if the valve nozzle terminates in an abrupt expansion with uniform downstream pressure to the point where valve flow expands to fill the entire discharge pipe flow area, one-dimensional momentum conservation leads to the interesting fact that pipe entrance velocity and throat velocity are equal:

$$V_E^2 = V_t^2 = k\, g_c \frac{2}{k+1} \frac{P_O}{\rho_O} \tag{7}$$

Moreover, equations 1 and 5 provide the entrance pressure and density as:

$$P_E = \frac{\dot{m}}{A} \sqrt{\frac{2}{k+1} \frac{1}{k\, g_c} \frac{P_O}{\rho_O}} \tag{8}$$

$$\rho_E = \frac{\dot{m}}{A} \sqrt{\frac{k+1}{2} \frac{1}{k\, g_c} \frac{P_O}{\rho_O}} \tag{9}$$

for supersonic flow.

Figure 6.2-3 shows important aspects of the discharge pipe submerged end. Pressure, P(t), is applied to the water column and accelerates it rightward against pool pressure, P_R. The inertia properties of surrounding pool water are included by the dotted volume identified as equivalent mass, which is approximately equal to one additional diameter of pipe length. The differential equation of motion is obtained from mass and momentum conservation as:

$$\left(L_{EQ} - Z_P\right) V_P \frac{dV_P}{dZ_P} = \frac{g_c}{\rho_L}\left(P(t) - P_R\right) \tag{10}$$

where the initial conditions:

$$Z_{P(o)} = 0$$

$$\frac{dZ_{P(o)}}{dt} = 0 \tag{11}$$

The stepwise solution of equation 10 provides rightward velocity of the gas-liquid interface, which provides interface pressure from a rightward traveling characteristic. The receiver pressure, P_R, is taken to be P_i. When the water plug is expelled ($Z_p \geq L_{sub}$), a sonic flow requirement determines the outflow boundary condition; i.e.:

$$V(L,t) = C(L,t) = \sqrt{k\, g_c \frac{P(L,t)}{\rho(L,t)}} \tag{12}$$

Symbol	Description
$\dot{m}$	mass flowrate
A	cross-sectional flow area
ρ_E	density at entrance
V_E	velocity at entrance
h_O	stagnation enthalpy
h_E	entrance enthalpy
g_c	gravitational constant
m_∞	mass flowrate at steady state
t_v	ramp time
t	time
k	ratio of specific heat at constant pressure to specific heat at constant volume
P_E	entrance pressure
P_O	stagnation pressure

Symbol	Description
ρ_O	stagnation density
V_t	throat velocity
C	velocity of sound at throat conditions
L_{EQ}	equivalent length
Z_P	arbitrary length defining wave boundary interface with water slug
V_p	velocity of point defined by Z_P
P_R	receiver pressure
ρ_L	liquid density

The SRV discharge line vacuum breakers are designed to have sufficient capacity to preclude the siphoning of water from the torus into the discharge line after an SRV cycle.

The required capacity was determined by assuming instantaneous condensation of the steam in the discharge line and requiring equalization of pressure between the discharge line and the drywell within 2 s.

A modified Darcy formula was used to select a valve having a larger capacity than required under existing parameters.

6.2.1.2.2 Secondary Containment System

The reactor building is designed to minimize the ground-level release of airborne radioactive material and permit the controlled elevated release of the building atmosphere. A discussion of reactor building design is provided in paragraph 3.8.4.1.

Portions of the reactor building provide secondary containment when the primary containment is closed and in service, and primary containment when the primary containment is open, as it is during refueling. The reactor building houses the following:

- Refueling and reactor servicing equipment.
- New and wet spent-fuel storage facilities.
- Other reactor auxiliary and service equipment, including:
  - Reactor core isolation cooling (RCIC) system.
  - Reactor water cleanup (RWC) system.
  - Standby liquid control system (SLCS).
  - Control rod drive (CRD) system equipment.

- ECCS.

- Electrical equipment components.

The reactor building is a Seismic Category I structure designed and constructed in accordance with all applicable local and State building code requirements.

Structural design features of the reactor building are illustrated on drawing nos. H-26096 and H-26098 through H-26105.

6.2.1.2.2.1 <u>Secondary Containment Bypass Leakage Determination</u>. An evaluation of the HNP-2 secondary containment system was performed using the guidance provided by BTP CSB 6-3, "Determination of Bypass Leakage Paths in Dual Containment Plants." Table 6.2-2 lists the piping systems identified as potential bypass leakage paths. The RHR system is a closed-loop Seismic Category I system within the secondary containment and, therefore, does not constitute a potential bypass leakage path. The drywell pneumatic system does not penetrate the secondary containment. Pneumatics are supplied to the drywell via a nitrogen supply with a source (2T48) external to the primary containment. The nitrogen supply was evaluated as a potential leakage path using BTP CSB 6-3. The use of nitrogen as motive gas for the drywell pneumatic system is bounded by the existing evaluation.

The total potential bypass leakage from the lines listed in table 6.2-2 does not exceed 2.0%/day of the design containment leakage. The resultant offsite radiological consequences of the design basis LOCA do not exceed the limits specified in 10 CFR 50.67.

As part of the implementation of alternative source term (AST) as described in subsection 15.1.11, when evaluating main control room doses due to the design basis LOCA, it is conservatively assumed that all the bypass leakage ends up in the main condenser through the following three potential paths listed in table 6.2-2, specifically the HPCI steam line condensate to the main condenser, the RCIC steam line condensate to the main condenser, and the RWC drainage to the main condenser. This assumption is necessary because of the location of the main control room in the HNP-1 and HNP-2 turbine buildings. To facilitate the crediting of secondary containment bypass leakage deposition in the main condenser to mitigate main control room doses due to the design basis LOCA, the three referenced bypass lines to the main condenser have been seismically verified and quality of the seismically verified equipment is maintained. This approach duplicates the approach used for the main steam isolation valve leakage treatment system described in subsection 9.5.10.

The reactor building closed cooling water (RBCCW) system surge tank is located in the reactor building at el 203 ft msl. In the unlikely event the piping inside the drywell fails, coincident with the design basis LOCA, any drywell atmosphere leakage that might pass the RBCCW system containment isolation valves will ultimately vent to the reactor building atmosphere via the RBCCW surge tank vent (drawing nos. H-26054 and H-26102).

The following system isolation valves are tested for leakage, as described in the Technical Specifications.

- Main steam drain valves (B21-F016, B21-F019).
- RWC valves (G31-F001, G31-F004).
- Equipment drain sump discharge (G11-F019, G11-F020).
- Floor drain sump discharge (G11-F003, G11-F004).
- Chemical drain sump discharge (G11-F852, G11-F853).
- HPCI turbine steam supply (E41-F002 and E41-F003).
- RCIC turbine steam supply (E51-F007 and E51-F008).

The reactor building chilled water system, the drywell chilled water system, and the RBCCW system are considered to be closed systems in that they:

- Do not directly communicate with the containment atmosphere following a LOCA.
- Are designed in accordance with quality group D standards (except for the piping penetrating the primary containment and the associated containment isolation valves that are quality group B).
- Meet Seismic Category I design requirements for piping systems.
- Are designed in excess of the primary containment design pressure and temperature.
- Are routed clear of postulated high-energy jet forces, pipe whip, and postulated missiles.

During normal plant operations, system integrity can be determined to be intact through system operation.

HNP-2 does not use guard pipes in association with the secondary containment system.

Table 6.2-2 provides the assumptions used in the derivation of the bypass leakage value.

6.2.1.2.2.2 Water Seal Analysis for Determination of Leakage Paths. The following outline describes the water seal analysis for determining the leakage paths for high-pressure coolant injection (HPCI), RCIC, radwaste, torus drainage and purification, and CRD hydraulic (CRDH) systems:

A. HPCI (drawing nos. H-26020, H-26021, H-26128, and H-26130)

As noted on drawing no. H-26020, the HPCI pump is normally aligned to take suction from the 500,000-gal condensate storage tank (CST). As a minimum, a water level of 15 ft above the tank bottom is maintained in the CST by the demineralized water makeup system, as described in subsection 9.2.6. Given the DBA (double-ended failure of the 28-in.-diameter recirculation line), the HPCI turbine pump can be estimated to operate for the period of time from LOCA signal initiation until the RPV blows down and steam pressure is insufficient to drive the HPCI turbine. Four transmitters and trip units (2E41-PT-N058A,B,C,D and 2E41-PIS-N658A,B,C,D), designed to sense HPCI steamline pressure, trip the motor-operated steamline isolation valves (F002 and F003) when steamline pressure falls below 100 psig, thus, stopping the turbine-driven pump within < 2 min following the accident.

Based upon the above information, the pump suction line remains filled with water, and the suction line connection to the CST is covered by a minimum of 15 ft of water. Since the CST bottom is located at grade elevation (130 ft msl), the resultant static head at valve 2E41-F004, as determined from the information on drawing no. H-26130, is ~ 48 ft. This static head is also applied to the HPCI pump suction side of valve 2E41-F041 (drawing nos. H-26128 and H-26130).

The design requirement to supply the HPCI pump with a water supply source from the containment suppression pool also establishes a water seal for valve 2E41-F042. In the event the HPCI pump suction source is transferred from the CST to the suppression pool, the water in the suppression pool forms a seal for valves 2E41-F004 and 2E41-F019.

Evaporative losses from the 500,000-gal CST have not been established, since complete evaporation of the CST water over the long-range cooling effort will not eliminate the suppression pool water seal.

The CST is acceptable as a water seal, since the tank is housed in a watertight, Seismic Category I, open-top retention system, as described in subsection 9.2.6. Should failure of the tank be postulated, the liquid within the tank will spill into the retention system. Although the liquid level will be reduced, an adequate head of water will continue to exist between the potential leak path and atmosphere for more than 30 days.

B. RCIC (drawing nos. H-26023, H-26024, H-26279, and H-26280)

As may be noted on drawing no. H-26023, the RCIC pump is normally aligned to take suction from the 500,000-gal CST through a piping configuration very similar to the piping configuration discussed for the HPCI pump. Given the DBA, the RCIC steam turbine-driven pump does not operate for a period > 2 min; therefore, a water seal similar to the seal for the HPCI pump is maintained.

C. Radwaste (drawing nos. H-26026 through H-26030, H-26104, and H-26391, and figures 3.8-9 and 11.2-1)

The drywell equipment and floor drain sump pumps are located in pump pits, the tops of which are located at el 114 ft 6 in. msl in the bottom section of the drywell. The drywell general arrangement is shown on drawing no. H-26104, and the centerline elevation of the drywell vents is shown on figure 3.8-9.

Following the postulated DBA, the nuclear process system blows down to the drywell. Water accumulates in the lower elevations of the drywell as a result of the blowdown, and a water level of ~ 6-in. above the drywell floor el 114 ft 6 in. is established. Flooding of the drywell floor, as described above, forms a water seal between the drywell atmosphere and the containment isolation valves; thus, these lines are considered only as a water source of bypass leakage.

D. Torus Drainage and Purification (drawing nos. H-26042 and H-26142)

As may be noted from the referenced drawings and subsection 9.3.7, valves 2G51-F011 and F012 may be assumed to be open at the time the DBA is postulated to occur. The appropriate accident signals effect closure of these valves, and following closure, the suppression pool water establishes a water seal.

E. CRDH System Return Header

The CRDH system return header discharges fluid to the nuclear boiler by way of the RWC system to the reactor feedwater piping (drawing no. H-26036).

Containment leakage available for bypass leakage through the CRDH system is already accounted for by evaluation of potential leakage past the reactor feedwater system check valves. Therefore, the CRDH system is not evaluated as a separate leakage path.

Figure 6.2-4 shows a typical spectacle flange arrangement and schematically locates the spectacle flange within the secondary containment. As may be noted, should leakage occur at the flange joint, the potential leakage will be to the secondary containment regardless of leakage direction.

6.2.1.2.2.3 **Reactor Building Penetrations.** Access openings for personnel and equipment are provided with interlocked doors equipped with weather-strip-type seals. The airtight door configuration is provided with an electrical control system to enforce procedures governing secondary containment integrity. Penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

6.2.1.2.2.4 Reactor Building Ventilation System. The reactor building ventilation system is discussed in detail in subsection 9.4.2.

6.2.1.3 Instrumentation Application

6.2.1.3.1 Primary Containment

The primary containment atmosphere monitoring system is discussed in detail in subsection 7.6.4.

6.2.1.3.2 Secondary Containment

The reactor building ventilation system normally controls secondary containment pressure. Pressure sensors outside the building are arranged so that the lowest pressure on the building (due to wind) is compared with the building internal pressure.

The secondary containment is isolated on the same signals that actuate the SGTS; i.e., high drywell pressure, RPV water level 2, reactor building ventilation exhaust radioactivity high, or refueling floor ventilation exhaust radioactivity high.

The systems whose signals initiate secondary containment isolation are discussed in subsection 7.3.2.

6.2.1.4 Tests and Inspections

6.2.1.4.1 Primary Containment

Paragraph 3.8.2.8 describes the tests and inspections provided for the various systems and components of the primary containment.

6.2.1.4.2 Secondary Containment

Activation of the SGTS demonstrates the integrity of the reactor building (secondary containment). The SGTS establishes and maintains a negative pressure (0.20 in. water) within the secondary containment, as described in subsection 6.2.4. The SGTS exhaust flowrate is recorded, and the secondary containment ΔP with respect to outside ambient conditions is indicated in the MCR. Secondary containment integrity is tested as required by the Technical Specifications.

Visual inspection of reactor building penetrations is possible. Penetration leakage can be determined as a part of the gross reactor building inleakage.

The frequency of secondary containment inspections, as defined in the Technical Specifications, is based upon expected life time of the various seals, components, penetrations, and anticipated failure modes. The inspection schedule is intended to ensure gross failures do not occur, and should such failures occur, they are discovered and corrected within a reasonable time period.

6.2.1.5 Materials

The organic materials used in the primary and secondary containments (paragraphs 3.8.2.7 and 3.8.4.6) were selected for extended life during normal operation and their resistance to expected accident environmental conditions. Thermal insulations are inorganic and are not sensitive to high-radiation fields, steam, and high temperature.
Evaluation of these organic materials determined they satisfactorily endure accident environmental conditions and their expected products of decomposition, if any, do not adversely affect the operability of any ESF.

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEM

6.2.2.1 Safety Design Bases

The containment heat removal system is an integral part of the RHR system and meets the following safety design bases:

A. The maximum long-term bulk temperature of the containment atmosphere does not exceed 150°F.

B. The source of water for restoring RPV coolant inventory is a closed cooling water loop.

C. A closed loop flowpath between the suppression pool and the RHR heat exchangers is established so the heat removal capability of the heat exchangers can be utilized.

D. This system, in conjunction with the other ECCS subsystems, has such diversity and redundancy that no single failure can result in its inability to adequately cool the core (paragraph 6.3.3.3).

E. Containment spray can be activated to maintain containment temperature and pressure within the design limits.

F. Each active component can be tested during normal operation.

6.2.2.2 System Description

Containment cooling is an integral part of the RHR system, as described in subsection 5.5.7. Redundancy is achieved by having two complete containment cooling modes.

Consideration of the fouling of heat exchangers and the selection of temperatures for heat exchanger design are discussed in subsection 5.5.7.

6.2.2.3 Instrumentation Application

The containment spray and the suppression pool cooling modes of the RHR system are manually initiated. Once initiated, containment cooling performance is monitored by monitoring pump performance, flow and pressure, and coolant temperature.

6.2.2.4 Safety Evaluation

In the event of a postulated LOCA, the short-term energy release from the reactor primary system is dumped to the suppression pool, causing a pool temperature rise of ~ 45°F. Subsequent to the accident, fission product decay heat results in a continuing energy dump to the suppression pool. Unless this energy is removed from the containment system, it eventually results in unacceptable suppression pool temperatures and containment pressures. The containment cooling mode of the RHR system is used to remove heat from the suppression pool. The RHR pumps draw water from the suppression pool and pass it through the RHR heat exchangers where the heat is transferred to the residual heat removal service water (RHRSW) system. The cooled water is diverted to spray headers in the drywell. Some of this flow can be diverted to the header above the suppression pool.

To evaluate the adequacy of the RHR system, the following sequence of events is assumed to occur:

1. With the reactor initially at 100.5% of maximum RTP, a LOCA is postulated.

2. A loss of offsite power (LOSP) occurs, and one onsite power supply division fails and remains out of service during the entire transient.

3. Immediately following the accident, the ECCS is activated. With the LOSP and only minimum onsite power, one CS and two RHR pumps are operable.

4. Approximately 10 minutes following ECCS activation, plant operators activate one RHR heat exchanger to start containment heat removal. This involves shutting down one of the two LPCI pumps and starting up the service water pumps for the heat exchanger.

5. Once containment cooling is established, no further operator actions are required.

When calculating the long-term post-LOCA pool temperature transient, it is assumed the RHRSW temperature is at its maximum value of 97°F throughout the transient. Use of this assumption maximizes the sink temperature to which the containment heat is rejected and thus, maximizes the containment temperature. In addition, the RHR heat exchanger is assumed to be in a fully fouled condition at the time the accident occurs. This assumption is also conservative, because it minimizes the heat exchanger heat removal capacity. Other key assumptions included in the design of the RHR system regarding the containment's response to a LOCA and net positive suction head (NPSH) are provided in paragraphs 6.2.3.1.1 and 6.3.3.9, respectively:

The resultant suppression pool temperature transient is described in paragraph 6.2.3.1.2.2. Even with the degraded conditions outlined above, the maximum temperature is only 210.2°F (Unit 1) and 207.5°F (Unit 2). Since the extended power uprate (EPU) analyses were based on a 10 CFR 50, Appendix K power level of 2818 MWt and remain unchanged, thermal power optimization (current rated thermal power level of 2804 MWt) does not impact the peak suppression pool temperatures. Evaluation was performed for reactor operating pressure increase to 1060 psia to address the impact on the suppression pool temperatures. The results of the evaluations concluded that there is no change to the peak suppression pool temperatures for both units.

It can be concluded that the conservative evaluation procedure described above clearly demonstrates the RHR system in the containment cooling mode can safely meet its design objective of terminating the post-DBA containment temperature and pressure transients.

A discussion of the protective features that prevent flooding of the containment heat removal pumps is provided in paragraph 9.3.3.2.

6.2.2.5 <u>Tests and Inspections</u>

The preoperational and operational testing, and the periodic inspection of components of the containment heat removal system are described in paragraph 5.5.7.5.

For the RHR system (containment heat removal), the pumps and valves may be tested at any time. The relief valves and spray nozzles are designed so they can be removed for bench testing that normally takes place during a major outage.

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

6.2.2.6 <u>Materials</u>

Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the system. For example, fluorocarbon plastic (Teflon) is not permitted in environments that obtain temperatures > 300°F, or neutron exposure above 10^4 nvt. Only inorganic thermal insulation, which does not decompose due to radiation or

temperature, is used in these environments. An inorganic zinc primer is used on all exterior surfaces of carbon steel components that are coated. All paints used are suitable for the temperature conditions expected.

6.2.3 SAFETY EVALUATION FOR CONTAINMENT FUNCTIONAL DESIGN (HNP-1 AND HNP-2)

The following safety evaluation and containment response to a LOCA analyses apply to HNP-1 and HNP-2 unless noted otherwise.

Original Containment Response. This paragraph describes the original HNP-1 and HNP-2 containment response evaluation that provides the basis for:

- The peak drywell pressure of 59.0 psig for HNP-1 and 57.5 psig for HNP-2 used for original primary containment leakage testing. (See paragraph 6.2.3.1.2.1 for the current operating conditions.)

- The LOCA radiological evaluation provided in subsection 15.3.3.

Figures 6.2-8 and 6.2-9 show the liquid blowdown pressure and temperature responses, respectively, from the reactor to the containment. Table 6.2-4 shows the reactor energy distribution at the time the break occurs.

The calculated containment pressure and temperature responses to the LOCA are shown on figures 6.2-10 through 6.2-12, respectively. The calculated peak drywell pressure is 59.0 psig for HNP-1 and 57.5 psig for HNP-2, which is 5% and 7.24%, respectively, below the maximum allowable pressure of 62 psig for this design.

For the steam line break within the containment, the typical peak-cladding temperature is ~ 600°F (section 6.3), because the break occurs at a higher RPV elevation. As a result, the ECCS effectively cools the core sooner since the steam leaving allows for faster depressurization.

Following a recirculation line break concurrent with a single active failure, at least one of the two CS trains and additional ECCS subsystems are available, as indicated in table 6.3-2.

The blowdown from the recirculation break is terminated ~ 35 s after the break. The maximum drywell pressure occurs during the reactor blowdown phase of the DBA.

The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the noncondensible gases in the drywell are initially forced into the suppression pool. However, the noncondensibles redistribute between the drywell and suppression pool via the vacuum breaker system as steam condensation decreases drywell pressure.

The low-pressure coolant injection (LPCI) mode of RHR and/or the core spray (CS) system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting

metal-water reaction to < 0.1%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges (within 250 s) through the recirculation line break into the drywell. The flow of water transports the core decay heat out of the RPV through the broken recirculation line in the form of hot water that flows into the suppression pool via the drywell to the suppression pool vent pipes. Even at ~ 250 s, steam flow is negligible. Following the discharge of primary coolant from the RPV into the drywell, the temperature of the suppression pool water approaches 140°F, and the suppression pool pressure stabilizes at ~ 27 psig. The steam flow, in addition to heat losses to the drywell walls, provides considerable cooling to the drywell atmosphere and causes a depressurization of the containment as the steam in the drywell is condensed.

The RHR/LPCI pumps used to flood the core can also be used as the containment spray pumps. Prior to activation of the containment cooling (arbitrarily assumed at 600 s following the accident), all LPCI pump flow is used to flood the core. After 600 s, the RHR pump flow can be manually diverted from the RPV to the containment spray in accordance with the Emergency Operating Procedures (EOPs). However, it should be noted that containment spray is not assumed in the analysis to be activated to keep the containment pressure below the containment design pressure. When using either the LPCI pumps or containment spray, the RHR heat exchangers are activated in accordance with the EOPs after the accident to limit the peak temperature of the suppression pool below the allowable limit.
They drywell and the suppression pool are conservatively designed to the same pressure of 56 psig without any additional energy inputs. The maximum allowable suppression pool bypass is 0.218 ft^2, which corresponds to a 6.325-in. line for a break of 0.42 ft^2. The allowable leakage for a DBA break of 4.378 ft^2 is 0.668 ft^2.

Containment pressure drops quickly following ECCS spillover with a 100% efficiency. It is conservatively assumed the ECCS spillover is reduced to 10%, resulting in a 20-psig pressure drop within 100 s, and continues to decrease. Hence, since no other steam generation occurs in the HNP-2 drywell, the HNP-2 containment atmospheric dilution (CAD) system can be manually initiated within 8 h with no adverse effect.

6.2.3.1 <u>Containment LOCA Analysis</u>

The information contained in this section is based on the containment evaluations performed at 2818 MWt (100.5% of the current operating level of 2804 MWt) and reactor operating pressure of 1060 psia.[39,40,41]

6.2.3.1.1 Introduction

The key design parameters for the containment are as follows:

- Drywell design pressure (56 psig).
- Drywell design temperature (281°F for HNP-1) (340°F for HNP-2).
- Suppression pool design pressure (56 psig).

- Suppression pool design temperature (281°F for HNP-1) (340°F for HNP-2).

Plant Hatch Units 1 and 2 have the Mark I primary containment design. The main function of the Mark I containment design is to accommodate pressure and temperature conditions during a LOCA within the drywell or a reactor blowdown through the SRV discharging piping, and thereby, to limit the release of fission products to values which will ensure offsite does rates below the 10 CFR 50.67 guideline limits. In the event of a pipe break in the drywell, water and steam from the RPV are discharged into the drywell. The resulting increase in the drywell pressure forces the water and steam, along with noncondensable gases initially existing in the drywell, through the vents which connect the drywell to the suppression pool. During a reactor blowdown through the SRVs the steam is directly discharged into the suppression pool. The primary containment can also accommodate dynamic loads resulting from the fluid motion during a LOCA or SRV actuation. These dynamic loads were defined during the Mark I Containment Long Term Program (LTP) and accepted by the NRC. The reactor blowdown flowrate is dependent on the reactor initial thermal hydraulic conditions, such as vessel dome pressure and the mass and energy of the fluid inventory in the RPV. The maximum drywell pressure occurs during the reactor blowdown phase of a LOCA and is dependent upon the rate at which primary system energy and fluid enter they drywell. The largest pipe in the primary coolant is the 28-in. diameter recirculation line. The instantaneous guillotine rupture of this pipe is the DBA for the containment design pressure.

The long-term heatup of the suppression pool following a LOCA or a transient is governed by the capability of the RHR system to remove decay heat which is transferred from the RPV to the suppression pool.

The evaluations performed for power operation at 2804 MWt and reactor operating pressure of 1060 psia are described below:[34,39,40,41]

- Short-term containment pressure and temperature response to a postulated design basis accident LOCA (DBA-LOCA).

- Long-term containment pressure and temperature response to DBA-LOCA.

- DBA-LOCA containment dynamic loads.

- Subcompartment pressurization.

- Drywell pressure and temperature response to small steam line breaks.

- Wetwell pressure and pool temperature response for the evaluation of the NPSH to core spray and RHR pumps.

- Small steam line breaks were analyzed to determine if the existing drywell environmental qualification (EQ) temperature profile still bounds the drywell temperature response.

- An analysis intended to minimize the calculated wetwell pressure response was performed to provide conservative data for NPSH evaluation at the current operating conditions.

6.2.3.1.2 Containment Response to LOCA

The instantaneous guillotine rupture of a main recirculation line results in the maximum flowrate of primary system fluid and energy into the drywell, resulting in the maximum containment ΔP.

Short-term blowdown mass and energy discharged for both steam line and recirculation line breaks are calculated using the applicable General Electric (GE) CIPT2 code that models the RPV as a single thermodynamic node using several heat slabs to represent the RPV, RPV internals, and fuel. Critical flow from the break is calculated with the Moody Critical Flow Model consistent with the requirements of 10 CFR 50, Appendix K.

Immediately following the rupture, the flow out of both sides of the break is limited to the maximum allowed by critical flow considerations. The conditions in the containment and primary system at the time of the accident are the maximum normal conditions described in subsection 15.3.3. Figure 6.2-5 shows a schematic view of the flowpaths to the break and the location of a recirculation line break. In the side adjacent to the suction nozzle, the flow corresponds to critical flow in the 3.667-ft^2 pipe cross-section. In the side adjacent to the injection nozzle, the flow corresponds to critical flow at the 10 jet-pump nozzles associated with the broken loop, providing an effective break area of 0.631 ft^2. In addition, a 4-in. cleanup line crosstie adds 0.08 ft^2 to the critical flow area considered, yielding a total of 4.378 ft^2. This break area is very conservative due to the use of nominal pipe internal diameters in all cases as opposed to effective areas.

The containment response to a LOCA is analyzed using the ESF flow input parameters and assumptions delineated in table 6.2-3. The key input assumptions used for the containment pressure and temperature analysis of the DBA-LOCA are listed below. (See also table 6.2-6.) For the analysis of steam line breaks, the input assumptions are the same as those for the DBA-LOCA long-term analysis except as noted otherwise in paragraph 6.2.3.1.4, where the steam line break analysis results are provided.

- The recirculation line is considered to be severed instantly, resulting in the most rapid coolant loss and depressurization, with coolant being discharged from both ends of the break.

- For both the short-term and long-term evaluations, the reactor is assumed to be operating at 102% of the extended uprate power, namely 2818 MWt, per Regulatory Guide 1.49. This represents 100.5% of the current rated thermal power of 2804 MWt.

- An instantaneous double-ended rupture of a recirculation suction line is assumed to occur.

- No credit for offsite power is assumed after the initiation of the accident and during the entire event.

- The core decay heat for the long-term containment response was based on the ANSI/ANS 5.1-1979 decay heat with two sigma uncertainly adders.

- No credit is taken for passive structural heat sinks in the drywell and suppression chamber (airspace and pool), except for the small steam line break analysis (paragraph 6.2.3.1.4).

- For the short term, the feedwater flow is assumed to stop instantaneously at time zero. This conservatism is used because the continued flow of relatively cold feedwater will depressurize the RPV, resulting in the reduction of discharged steam and water into the primary containment. In addition, the main steam isolation valve (MSIV) rapid closure cuts off power to the steam-driven feedwater pumps.

- For the long-term pool heatup analysis, the reactor feedwater is assumed to flow into the RPV only until all high-temperature feedwater (water that would contribute to pool heatup) is injected into the RPV.

- The reactor is assumed to shut down upon accident initiation because of void formation in the core region. A scram also occurs in < 1 s from receipt of the high drywell pressure signal, and the time difference between shutdown at time 0 and time 1 s is negligible (assumed to occur simultaneously).

- The initial drywell temperature is assumed to be 150°F. The initial suppression pool temperature is assumed to be 100°F.

- The the short-term evaluation, where peak drywell pressure is of concern, the initial pressure is assumed to be 1.75 psig, whereas 0 psig is assumed for the long-term pool temperature evaluation in conjunction with the NPSH evaluation for ECCS and RHR pumps.

- For the short-term evaluation, where peak drywell pressure is of concern, the initial humidity is assumed to be 20% (low end of expected value) to maximize air mass for maximum calculated pressure response. On the other, 100% humidity is assumed for the long-term NPSH evaluation for ECCS and RHR pumps to minimize the calculated containment pressure response.

- All of the motor power ratings for operating RHR and ECCS pumps is added to heat the water downstream of the pumps.

- For the long-term pool temperature evaluation, the RHR heat exchanger is assumed to be activated at 600 s into the event.

- The service water temperature remains at 97°F throughout the event.

- For the long-term response evaluation, the RHR flowrate is assumed to be 7,700 gal/min.

- For the long-term response evaluation, the minimum pool volume for each unit is assumed to maximize the long-term pool temperature response. For the short-term response evaluation, the maximum pool volume for each unit is used to maximize the short-term pressure response.

- CRD flow is assumed to be zero.

- The sensible heat released in cooling the fuel to 552°F and the the core decay heat are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization. Because of this assumed high-energy release rate, the RPV is maintained at nearly rated pressure for ~ 11 s. The high RPV pressure increases the calculated blowdown flowrates. The is conservative for containment analysis purposes.

- With the RPV fluid temperature remaining near 552°F, the release of sensible energy stored below 552°F is negligible during the first 11 s. The later release of sensible energy does not affect the peak drywell pressure. The small effect of this energy on the end-of-transient suppression pool temperature is included in the calculations.

- The MSIVs are assumed to begin closing at 0.5 s after the accident and be fully closed within 5 s following closure initiation. By assuming MSIV rapid closure, the RPV is maintained at a high pressure that maximizes the discharge of high-energy steam and water into the primary containment.

- RPV depressurization flowrates are calculated using Moody's critical flow model(4) of liquid-only outflow, since this assumption maximizes the energy release to the containment. Liquid-only outflow assumes all vapor formed in the RPV by bulk flashing rises to the surface rather than being entrained in the existing flow. Some of the vapor is entrained, significantly reducing the RPV discharge flowrates. Moody's critical flow model, which assumes annular, isentropic flow; thermodynamic phase equilibrium; and maximized slip ratio, accurately predicts RPV outflows through small-diameter orifices. However, actual rates through larger flow areas are less than the model indicates because of the effects of a near homogeneous two-phase flow pattern and phase nonequilibrium. This effect is in addition to the reduction caused by vapor entrainment discussed previously. Figures 6.2-6 (Unit 1) and 6.2-7 (Unit 2) show the liquid and steam blowdown flowrates from the reactor to the containment at the current operating conditions.

The GE models used for short-term pressure and temperature response differ from the models used for long-term response.(34) The short-term models and application methodology maximize the calculated pressure response for the first 30 s following a LOCA, since this is the time period in which peak pressure is closest to containment design limits. The short-term containment response is discussed in paragraph 6.2.3.1.2.1. As such, the final temperature and pressure at 30 s post-LOCA short-term differs from the long term.

The long-term containment response results in the most limiting suppression pool temperature and the discussion is provided in paragraph 6.2.3.1.2.2.

The peak drywell pressure for expanded operating domain (EOD) operation is also calculated(9) using break flowrates and enthalpies calculated by a more mechanistic blowdown model(6) that provides a more realistic prediction of the DBA-LOCA blowdown for operating conditions in EOD, including consideration of final feedwater temperature reduction at selected operating conditions.

For the introduction of the GNF2 fuel design, long-term containment analyses for DBA-LOCA and drywell EQ was evaluated, and it was concluded that the small increase in GNF2 decay heat against the current design basis decay heat has an insignificant effect on the peak values (pool temperature and long-term containment pressure) in the analyses.(47)

For the introduction of the GNF2 fuel design, long-term containment analyses for DBA-LOCA and drywell EQ was evaluated, and it was concluded that the small increase in GNF2 decay heat against the current design basis decay heat has an insignificant effect on the peak values (pool temperature and long-term containment pressure) in the analyses.(47)

6.2.3.1.2.1 Short-term Containment Pressure and Temperature Response to DBA-LOCA. The short-term response was performed in accordance with Regulatory Guide 1.49 and reference 40 using the M3CPT computer code. The analysis was performed at various reactor operating conditions associated with plant performance improvements, such as maximum extended load line limit (MELLL) and final feedwater temperature reduction (FFWTR). The analyses used blowdown flowrates based on the blowdown model built into M3CPT and the LAMB blowdown model. In using the LAMB blowdown model, the blowdown is calculated first using the LAMB code; then the LAMB flow versus time is used as input to M3CPT.

M3CPT calculations based on LAMB blowdown flow time histories are performed for all reactor operating points considered, whereas the M3CPT blowdown model is used only for the 100% power and the rated core flow point. The short-term response performed with M3CPT blowdown is the basis for the peak containment pressure of 50.78 psig for Unit 1 and 47.22 psig for Unit 2.

In addition, LAMB blowdown flow obtained for Unit 1 is also used for the Unit 2 analysis. The use of Unit 1 blowdown flow for Unit 2 is considered conservative because the blowdown flow for Unit 1 is higher at the same reactor power/flow point due to higher degree of subcooling for Unit 1 in the downcomer region.

The DBA-LOCA event (a double-ended break of a recirculation suction line) is assumed to occur at the following operating points:

- Rated core flow and power level of 2818 MWt (100.5% of the current power level of 2804 MWt).

- Minimum core flow with FFWTR at 2818 MWt (maximum subcooled condition).

Comparison of responses at the conditions defined above shows the impact of subcooling on the containment response to DBA-LOCA. It is generally considered that containment loads will be higher with higher subcooling because a higher subcooling will result in a higher blowdown flow for a given pressure.

The containment peak pressure was analyzed using the M3CPT built-in blowdown flow model for 100.5% of the current rated thermal power conditions, and the pressure and temperature responses for these operating points were compared with the plant unique load definition (PULD) results.[9,10]

The short-term containment analysis concluded:

- The peak DW pressures calculated for all cases are below the DW design pressure (figures 6.2-17 through 6.2-20) and are as follows:

  Unit 1 50.78 psig
  Unit 2 47.22 psig

  These values are used for 10 CFR 50, Appendix J testing (subsection 18.2.14).

- For Unit 2 the calculated peak DW temperature is below the design temperature of 340°F. For Unit 1, the peak DW (ambient) temperature is above the design temperature of 281°F, but only for a short period of time (first ~ 15 seconds). Since the DW shell is initially at 150°F and the DW ambient temperature is only about 15°F above the design temperature, the DW wall temperature is expected to remain below the design temperature.

Dynamic Loads Evaluation

The vent system thrust loads, pool swell loads, condensation oscillation (CO) loads, and chugging loads were evaluated at the current operating conditions, using M3CPT results obtained with LAMB break flow time histories. Various reactor operating conditions were considered in the evaluation. The evaluation results are summarized below.

<u>Vent System Thrust Load</u>

Using M3CPT results based on LAMB break flow time histories, the vent system thrust loads were calculated for the previous rated thermal power level according to the method described in the Mark I load definition report.[11]

Evaluation of the peak vent system thrust loads determined with M3CPT output based on LAMB break flows are bounded by PULD values.

The extended power uprate analysis concluded that the vent system thrust loads were bounded by the loads defined in the PULD reports.

The vent system thrust load evaluations performed for reactor operating pressure increase to 1060 psia demonstrated that the vent system thrust loads for Unit 2 exceeded the PULD loads. The force components for reactor operating pressure increase are expected to increase approximately 11%. However, it was concluded that, based on the inherent margins in the existing analyses, there will be no significant impact on the containment structures. The vent system thrust loads for Unit 1 remain bounding.

Pool Swell Load

Pool swell occurs immediately after the DBA-LOCA. The basis for the Hatch pool swell load is the Quarter Scale Test Facility (QSTF) tests.[31] The results of these tests were used to develop the pool swell forces given in the PULD reports.[9,10] These loads were subsequently evaluated for Units 1 and 2 in the Plant Unique Analysis Report (PUAR).[37,38]

Evaluation of the results of the analysis show that for both Hatch units the design basis pressurization rate bounds the initial pressurization rate calculated with EPU operation; therefore, the design basis pool swell loads remain bounding.

Based on the results of the evaluation performed for reactor operating pressure increase, the pool swell loads for Unit 2 were estimated to increase by approximately 4.4%. However, it was concluded that, based on the inherent margins in the existing analyses, there will be no significant impact on the containment structures. The pool swell loads for Unit 1 remained bounding.

Condensation Oscillation Load

The design condensation oscillation (CO) load for Units 1 and 2 is based on the Generic Mark I CO load given in reference 11. This load was derived from CO data recorded during tests (M8, M11, and M12) at the Mark I Full-Scale Test Facility (FSTF).[32]

The FSTF CO tests were run for a wide range of blowdown and containment conditions to bound all Mark I plants. These test conditions for CO load continue to bound the blowdown and containment conditions predicted at various reactor power/flow operating points for Units 1 and 2. Therefore, the current design CO load is not impacted by the reactor operating pressure increase conditions.

Chugging Load

Chugging may occur when the steam mass flux through the vent is not high enough to maintain a quasi-steady steam/water interface at the vent exit. This means that chugging could occur at the tail end of a postulated DBA or intermediate-size break accident (IBA) or anytime during a postulated small-size break accident (SBA) with the reactor at pressure.

The design chugging load for Hatch is based on the FSTF full scale tests.[32] These tests were run for a range of blowdown and containment conditions developed to bound all Mark I plants. These conditions continue to provide a bounding envelope for chugging at reactor operating pressure increase conditions for Units 1 and 2.

Therefore, the current chugging loads remain applicable to the reactor operating pressure increase conditions.

SRV Containment Dynamic Loads

The controlling parameters for the SRV loads include safety relief valve discharge line (SRVDL) and containment geometry, initial water leg length in the SRV discharge line, and SRV flowrate (primarily determined by the SRV setpoints, line geometry, and line losses). The SRV discharge loads can be divided into the following two main categories:

First SRV Actuations

Loads due to initial SRV actuations are determined by parameters including the SRV setpoints, SRVDL volume, line lengths, friction losses, and number of turns. Because all these parameters, including the SRV setpoints, do not change, loads due to initial SRV actuations are not impacted by the reactor operating pressure increase to 1060 psia.

Subsequent SRV Actuations

Loads due to subsequent SRV actuations depend primarily on the SRVDL reflood height at the time of SRV opening and SRV setpoints. The SRVDL for plant Hatch is the maximum flood height, which is controlled by the SRVDL geometry and the SRVDL vacuum breaker capacity. Because all these parameters, including the SRV setpoints, do not change, loads due to subsequent SRV actuations are not impacted by the reactor operating pressure increase to 1060 psia.

Therefore, the current SRV discharge loads remain applicable to the reactor operating pressure increase conditions.

Hence, the peak containment pressures and temperatures and the dynamic loads for the short-term containment pressure and temperature response to a DBA-LOCA remain within the existing design parameters.

6.2.3.1.2.2 Long-term Containment Pressure and Temperature Response to DBA-LOCA. To assess the primary containment long-term response following the accident, the effects of various containment spray and containment cooling combinations were evaluated. The initial pressure response of the containment (the first 30 s following the break) is the same for each cooling combination. For all combinations, one CS loop was assumed to be in operation. The long-term pressure and temperature response of the primary containment was evaluated for the following RHR containment cooling mode combinations:

- Operation of both RHR cooling loops - four RHR pumps, four RHRSW pumps, and two RHR heat exchangers - with containment spray.
- Operation of one RHR cooling loop with two RHR pumps, two RHRSW pumps, and one RHR heat exchanger - with containment spray.

- Spray cooling combination - operation of one RHR cooling loop with one RHR pump, two RHRSW pumps, and one RHR heat exchanger - with containment spray.

- Most limiting cooling combination - operation of one RHR cooling loop with one RHR pump, two RHRSW pumps, and one RHR heat exchanger - no containment spray.

During the long-term containment response (after RPV depressurization is complete), the suppression pool is assumed to be the only heat sink in the containment system. The effects of decay energy and stored energy on the suppression pool temperature are considered.

Most Limiting Cooling Combination

The most limiting cooling combination is exactly the same as the spray cooling combination except that the drywell spray is not operating. During this mode of operation, RHR pumps draw suction from the suppression pool and discharge flow through the RHR heat exchangers where it is cooled and injected back into the suppression pool. The CS system provides core cooling.

The containment pressure response to this set of conditions is shown on figure 6.2-21. The corresponding drywell and suppression pool temperature responses are shown on figures 6.2-22 and 6.2-23, respectively. A summary of the most limiting cooling combination is as follows:

RHR Loops	RHR Pumps	RHRSW Pumps	Containment Spray (gal/min)	CS (gal/min)	Peak Pool Temp (°F)	Secondary Peak Pressure (psig)
1	1	2	0	4000	210.2 (HNP-1)	27.0 (HNP-1)
					207.5 (HNP-2)	25.9 (HNP-2)

When comparing the spray cooling combination with the most limiting cooling combination, the suppression pool temperature response is the same, because the same amount of energy is removed from the pool regardless of whether the exit flow from the RHR heat exchanger is returned to the pool or injected into the drywell as spray. The fact that the peak containment pressure is higher for the most limiting cooling combination is of no consequence, because the pressure is still significantly lower than the containment maximum allowable pressure of 62 psig.

6.2.3.1.2.3 Mark I Long-Term Containment Program Evaluation. The HNP-1 and HNP-2 containment pressure responses[9,10] due to a postulated design basis LOCA were evaluated as part of the Mark I Long-Term Containment Program, which forms the bases for the PUARs. The Mark I Long-Term Containment Program[11] included plant-unique analyses of the containment

LOCA pressure and temperature response using the homogeneous equilibrium model for vessel blowdown[4] and the containment response model.[5]

The original Mark I Long-Term Containment Program evaluation is provided in section KA for HNP-1 and section 3.8B for Unit 2.

6.2.3.1.2.4 Subcompartment Pressurization. The Unit 2 licensing basis includes subcompartment pressurization. Due to changes in operating conditions with the extended power uprate, the mass and energy releases from the postulated pipe breaks in the annulus between the reactor vessel and biological shield wall are affected.

The mass and energy releases calculated for extended power uprate were used to evaluate the annulus pressurization (AP) loads (Supplement 6A). The original AP load analysis was evaluated with respect to the updated mass and energy release rates. The evaluation concluded that the original AP load analysis has sufficient conservatism to accommodate the slight increase in the mass release rates due to extended power uprate.

The results of the evaluation performed for reactor operating pressure increase to 1060 psia conclude that there will be no significant change to the AP loads.

The plant licensing basis for Unit 1 does not include subcompartment (annulus between the RPV and biological shield wall) pressurization.

6.2.3.1.3 Intermediate Breaks

The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the containment performance evaluation, the consequences of intermediate breaks are analyzed. This classification covers breaks for which ECCS operation occurs during the blowdown and breaks that result in RPV depressurization. This section describes the consequences of a 0.1-ft^2 break below the RPV water level to the containment. These breaks can involve either reactor steam or liquid blowdown. Figures 6.2-8 and 6.2-9 show the drywell and suppression chamber pressure and temperature responses as a result of liquid breaks. The ECCS response is discussed in subsection 6.3.3.

Following the 0.1-ft^2 break, drywell pressure increases at the rate of ~ 1.2 psi/s. The drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the vents is negligible, and the vents clear when the suppression chamber-to-drywell ΔP is equal to the vent submergence pressure. The maximum distance between the pool surface and the bottom of the vents is 4.333 ft. Thus, the water level in the annulus reaches 4.333 ft when the drywell-to-containment ΔP reaches 1.9 psi; i.e., ~ 1.6 s after the 0.1-ft^2 break occurs. At this time, air, steam, and water start to flow from the drywell to the suppression pool. The steam is condensed, and the air enters the suppression chamber free space. After 1.6 s, a constant ΔP of 1.9 psi exists between the drywell and the suppression chamber. The suppression chamber gradually pressurizes as the result of continual purging of drywell air. Within ~ 40 s, all drywell air has been swept over to the suppression chamber. Subsequently, the drywell and the suppression chamber pressures rise at a slower rate because of the continued pool heatup.

The operation of each initiated ECCS subsystem depressurizes the reactor within ~ 600 s, terminating the blowdown phase of the transient, and provides emergency core cooling.

The drywell is at ~ 25 psig, and the suppression chamber is at ~ 23 psig. For a DBA, the suppression chamber temperature is the same as at the end of blowdown, because essentially the same amount of reactor energy is released during the blowdown. Following the RPV depressurization, the flow through the break changes to suppression pool water the ECCS is injecting into the RPV. This flow condenses the drywell steam and eventually causes the drywell and containment pressures to equalize in the same manner as following a recirculation line rupture.

The subsequent long-term suppression pool and containment heatup transient that follows is essentially the same as the transient for the recirculation line break.

Based upon the above discussion, it can be concluded that the consequences of an intermediate break are less severe than the consequences of a recirculation line rupture.

Based on the results of the evaluations performed for reactor operating pressure increase to 1060 psia it is concluded that there will be no significant impact on the results of the existing analysis for intermediate line breaks.

6.2.3.1.4 Small Breaks

This paragraph discusses the containment transient associated with small primary system blowdowns. The sizes of primary system blowdowns in this category are the blowdowns that do not result in RPV depressurization due to either the loss of reactor fluid or the automatic operation of the ECCS equipment. The underlying assumption is that, following the manifestation of a break of this size, an orderly shutdown and depressurization of the plant are initiated.

The thermodynamic process associated with the blowdown of primary system fluid is one of constant enthalpy. If the break is below water level, the blowdown flow consists of reactor water. Upon depressurizing from RPV pressure to drywell pressure, approximately one-third of the water flashes to steam and two-thirds remain as liquid. Both phases are at saturated conditions corresponding to drywell pressure. Thus, if the drywell is at atmospheric pressure, the steam and liquid associated with a liquid blowdown are at 212°F. Similarly, if the containment is assumed to be at maximum allowable pressure, the reactor liquid blows down to ~ 309°F steam and water.

If the location of a primary system rupture results in the blowdown flow consisting of reactor steam, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. A constant enthalpy decompression of high-pressure saturated steam results in a superheat condition. For example, decompression of 1000 psia steam to atmospheric pressure results in 298°F superheated steam (86°F of superheat).

A small reactor steam leak imposes the most severe temperature conditions on the drywell structures and the safety equipment. The superheat temperature for large steam-only blowdowns is the same as for small breaks. However, the duration of the high-temperature condition is less, because the larger breaks depressurize the RPV more rapidly than the orderly reactor shutdown that is assumed to terminate the small break.

For the drywell design evaluation, the sequence of events described below is assumed to occur.

1. With the reactor and the containment operating at the maximum normal conditions defined in table 6.2-6, a small break occurs, allowing the blowdown of reactor steam to the drywell.

2. The resulting drywell pressure increase leads to a high drywell pressure signal that scrams the reactor and activates the containment isolation system.

3. Drywell pressure continues to increase at a rate dependent upon the size of the assumed steam leak, thereby depressing the water level in the vents until the level reaches the bottom of the vents.

4. Air and steam enter the suppression pool. The steam is condensed, and the air passes to the suppression chamber free space, resulting in a gradual pressurization of the containment at a rate dependent upon the air carryover rate.
5. Eventually, the entrainment of drywell air in the steam flow through the vents results in all drywell air being carried over to the suppression chamber.

6. Pressurization of the containment ceases and the system reaches an equilibrium condition with the drywell pressure at 25 psig and the suppression chamber at ~ 23 psig. The drywell is full of superheated steam.

7. Continued blowdown of reactor steam is condensed in the suppression pool.

8. The reactor is shut down in an orderly manner, using the main condenser and limiting the reactor cooldown rate to 100°F/h. As a result, the reactor is depressurized within 6 h, the blowdown flow to the drywell ceases, and the superheat condition is terminated.

If it is determined the reactor should be cooled down and depressurized to > 100°F/h, the drywell superheat condition is shorter. The temperature resulting from the blowdown is determined by finding the combination of RPV pressure and containment pressure that produces the maximum superheat temperature. The temperature is assumed to exist for the initial 3 h of the blowdown.

Small-Break Analysis for Equipment Qualification (EQ)

Small steam line breaks were analyzed to determine if the existing drywell temperature envelope for EQ envelops the drywell temperature response under the current operating conditions. The drywell temperature response to small steam line breaks was analyzed with the SHEX computer code for up to 1 day of event time, using the same methodology used for the

long-term containment response analysis to DBA-LOCA. A simplified model was used to continue the drywell temperature response calculation. It is assumed that the operator takes actions to initiate wetwell and drywell sprays in accordance with the Emergency Operating Procedures (EOPs).

Steam line breaks of 0.01 ft^2, 0.10 ft^2, and 0.50 ft^2 were analyzed for the current plant operating conditions at reactor operating pressure of 1060 psia.[44, 46]

Key analysis input assumptions are the same as the DBA-LOCA analysis assumptions summarized in paragraph 6.2.3.1.2., except as noted below.[44, 46]

- The initial reactor dome pressure is 1063 psia.

- HPCI may not be available for the small steam line break events due to either a postulated break in the HPCI steam supply line or due to an assumed single active failure. Hence, no credit is taken for the HPCI system.[44,45]

  The assumption of HPCI being available in the existing analysis was potentially nonconservative. The injection of relatively cold water into the vessel depressurizes the vessel, which reduces the steam flow from the break to the drywell and, in turn, can result in a lower calculated drywell temperature response during periods of HPCI injection.

- The decay heat curve is based on ANSI/ANS-5. 1-1979 nominal decay heat and on GE14 24-month cycle parameters.

- A pool temperature dependent RHR heat exchanger coefficient (K) is used for the purposes of this analysis. This K value is consistent with RHR flowrate of 7,700 gpm through the RHR heat exchanger.

- Credit is taken for the torus shell above the water line as a wetwell airspace heat sink, (in addition to the drywell heat sinks corresponding to the drywell and vent system steel shell).

The results of the analysis conclude the following:

- For 0.01 ft^2 break, the peak DW temperature is 289°F and also occurs at the start of drywell spray (around 1800 s for this case) (figure 6.2-24).

- For 0.1 ft^2 break, the peak DW temperature is 324°F and occurs just before the start of drywell spray around 600 s (figure 6.2-24).

- For 0.5 ft^2 break, the peak DW temperature is 327°F and occurs before drywell spray is activated (figure 6.2-24).

Therefore, it is concluded that the 329°F peak DW temperature obtained in reference 43 and 46 still bounds the peak DW temperatures obtained at the current operating conditions. Table 6.2-7 provides the drywell temperature envelope for break sizes 0.01 ft^2, 0.1 ft^2, and 0.5 ft^2.

6.2.3.1.5 Analytical Models

The analytical models, assumptions, and methods GE used to evaluate the containment response during the reactor blowdown phase of a LOCA are described in reference 5.

Long-term pressure and temperature responses for a period following the RPV blowdown phase of the LOCA are calculated in a manner similar to the calculation method used for the short-term blowdown phase. The model used for the long-term response calculations is basically the same as the model for the short-term response calculations, except for the following long-term response modeling features:

A. A simpler model is used for calculation of vent flow between the drywell and suppression pool, which is simply based upon a pressure difference between the two regions, without considering inertia effects.

B. Heat transfer to service water in the RHR heat exchanger is modeled using an overall heat transfer coefficient calculated for a given combination of RHR flowrate and service water flowrate.

C. The effect of containment sprays, if activated, on the drywell and wetwell airspace pressure and temperature responses is modeled.

6.2.3.1.6 Transient Energy Release Rates

This section contains a description of the transient energy release rates from the reactor primary system to the containment system following a LOCA with minimum ESF performance.

In general, a very conservative analytical approach is taken in that all possible sources of energy are accounted for, whereas the suppression pool is assumed to be the only available heat sink. No credit is taken for either the heat that is stored in the suppression pool and drywell structures, or the heat that is transmitted through the containment and dissipated to the environment.

The heat removal rate is analyzed for the following two cases:

A. Operation of Both RHR Cooling Loops

This case assumes all ECCS equipment is available following the LOCA, including both RHR heat exchangers and the necessary service water pumps.

B. Most Limiting Cooling Combination

This case is for the very degraded minimum cooling condition that limits the heat removal capacity to one heat exchanger. Paragraph 6.2.3.1.2.2 provides a more detailed description.

For both cases, it was assumed that at the time of the accident, the RHRSW temperature was 95°F. This temperature is unlikely to exist for more than a limited period in the summer. The ultimate heat sink temperature limit (RHRSW temperature) is 97°F. An RHRSW temperature of 97°F would result in an insignificant decrease in the rate at which the energy leaves after the first 10 min (initiation of suppression pool cooling) compared to that provided by figure 6.2-34.

To establish the energy distribution as a function of time (short term and long term), the following energy rates are required:

- Blowdown energy rates (primary system steam flow in preceding tabulation).
- Decay heat rate, fuel relaxation energy (normalized core heat in preceding tabulation).
- Sensible heat rate (figure 6.2-34).
- Pump heat rate value. The pump heat rate value used in the evaluation of the containment response to a LOCA for the maximum number of pumps in use is 4242 Btu/s.
- Heat removal rate from suppression pool.

Table 6.2-8 shows a tabulation of the blowdown flowrates assumed to occur as a result of the instantaneous rupture of a main recirculation line.

The following is a tabulation of the core decay heat values used in the evaluation of the containment response to a LOCA at power uprate conditions. The normalization factor is core power at the current RTP level.

Time(s)	Normalized Core Heat	Time (s)	Normalized Core Heat
0.0	1.0	30	0.0393
1.0	0.332	100	0.0312
2.0	0.149	10^3	0.0196
5.0	0.0598	2×10^3	0.0160
7.0	0.0545	10^4	0.00972
10.0	0.0484	2×10^4	0.00859
20.0	0.0422	10^5	0.00572

Following a LOCA, the sensible energy stored in the reactor primary system metal is transferred to the recirculating ECCS water and thus, contributes to the suppression pool and containment heatup. Figure 6.2-34 shows the rate at which this energy leaves the various primary system structures. Figure 6.2-34 is for 95°F RHRSW temperature. The ultimate heat sink temperature limit (RHRSW temperature) is 97°F. An RHRSW temperature of 97°F would result in an insignificant decrease in the rate at which the energy leaves after the first 10 min (initiation of suppression pool cooling) compared to that provided by figure 6.2-34.

The transient energy release rates are based on 10 CFR 50, Appendix K power level of 2818 MWt and remain unchanged for thermal power optimization (2804 MWt) and reactor operating pressure increase to 1060 psia.

6.2.3.1.7 Steam Bypass (HNP-2)

The HNP-1 steam bypass system is discussed in HNP-1-FSAR paragraph 5.2.4.4.

The boundary separation structures between the drywell and the suppression chamber, including the vent pipes, vent header, and downcomers, are fabricated, erected, and inspected by nondestructive examination methods in accordance with and to the acceptance standards of the ASME Code, Section III, Subsection NE. This superior construction and inspection quality control ensure the integrity of this boundary. The design pressure and temperature for this boundary were established at 56 psig and 340°F, respectively. Actual accident ΔP and temperature across this boundary are < 34.4 psid and ~ 184°F.

With the exception of the vacuum breaker seats, all penetrations of this boundary are welded. All penetrations are available for periodic visual inspection.

The RCIC and HPCI turbine exhaust systems and the main steam discharge system are the only systems that contribute steam to the suppression pool. The RCIC turbine exhaust system and the associated submergence below suppression pool water level are described in subsection 5.5.6 and shown on drawing no. H-26023. The HPCI turbine exhaust system and the associated submergence below suppression pool water level are described in paragraph 6.3.2.2 and shown on drawing no. H-26020.

A description of the main steam system is provided in supplement 5A and paragraph 5.2.2.2.3. Figure 5A-5 shows the schematic arrangement of the main steam discharge piping. Bypassing of the suppression pool is prevented by submerging the main steam discharge pipe discharge point ~ 7.5 ft below the suppression pool normal water level.

All external paths of potential bypass leakage, such as the purge and vent system, were reviewed. Every path has at least two isolation valves in the leakage path. These valves are high-quality containment isolation valves and are all normally closed leaktight valves.

The HNP-2 containment was examined to determine what leakage between the drywell and the suppression chamber can be tolerated. Figure 6.2-35 shows the allowable leakage capacity $(A/\sqrt{K})$ as a function of primary system break area where:

A = area of leakage flow

K = total geometric loss coefficient associated with A.

The maximum allowable leakage capacity is $(A/\sqrt{K})$ = 0.126 ft^2. Typically, the geometric loss factor is ≥ 3; thus, the maximum allowable leakage area is 0.218 ft^2. This corresponds to a 6.325-in. line.

When calculating the allowable leakage capacities shown on figure 6.2-35, the following assumptions were made:

A. Flow through the postulated leakage path is pure steam. For a given leakage path, assuming the leakage flow consisted of a mixture of liquid and vapor increases the total leakage mass flowrate and decreases the steam flowrate. Since the steam entering the suppression chamber free space results in containment pressurization, this is a conservative assumption.

B. No condensation of the leakage flow occurs on either the suppression pool surface or the torus and vent system structures. Since any condensation results in less steam in the suppression chamber free space, this is a conservative assumption. In practice, condensation does occur, especially for the larger primary system breaks, when vigorous agitation at the pool surface occurs during blowdown.

Figure 6.2-35 is a composite of 2 curves. Primary system breaks > ~ 0.4 ft^2 result in rapid primary system depressurization. Figure 6.2-36 shows the containment transient associated with breaks within this range. For a given primary system break area, the allowable leakage capacity results in the containment pressure being equal to the design pressure at the end of the reactor blowdown period.

Primary system breaks < ~ 0.4 ft^2 do not result in rapid primary system depressurization, and operator action is required to terminate the pressure rise in the containment. When determining the allowable leakage capacities shown on figure 6.2-35, it was assumed that:

A. Immediately following the small primary system break, containment pressure rises rapidly as the noncondensible gases in the drywell are washed over the suppression chamber. During this portion of the transient, it is assumed the plant operators believe everything is functioning normally, because they do not realize a leakage path exists. Under normal operating conditions, the maximum pressure that can occur in the suppression chamber is 25 psig, which is the pressure that results if all the noncondensible gases initially in the containment are carried over to the suppression chamber free airspace.

B. The plant operators realize a leakage path exists only when the suppression chamber pressure reaches 35 psig, concurrent with a 10-min delay, before any action is taken to terminate the transient. The corrective action taken 10 min after containment pressure exceeds 35 psig is a time critical operator action as defined in FSAR subsection 15.1.5 and is assumed to take 5 min to become effective. At

that time, the containment pressure is equal to the design pressure if the allowable leakage has occurred. The operators determine the source of leakage by either depressurizing the primary system via the main condenser or the SRVs, or activating the containment sprays. Figure 6.2-37 shows the containment response to a typical small break.

Results of the evaluation for reactor operating pressure increase to 1060 psia conclude that the maximum allowable bypass leakage area between the drywell and wetwell air space remains unchanged, with no impact on the drywell bypass leakage.

6.2.3.1.8 Subcompartment Pressurization (HNP-2)

Results of analyses performed on subcompartment pressurization due to breaks inside primary containment are provided in supplement 6A.

6.2.3.1.9 Moody Blowdown Model (HNP-2)

The Moody blowdown model is provided in supplement 6A.

6.2.3.1.10 Secondary Containment Pressure-Temperature Response Following a LOCA in the Primary Containment (HNP-2)

The following assumptions were made in the analysis of the pressure-temperature response in the secondary containment following a LOCA in the primary containment:

A. The secondary containment is divided into seven subcompartments:

- Main reactor building volume above el 130 ft.
- Torus chamber room.
- CRD corner room.
- RCIC corner room.
- Northeast RHR/CS corner room.
- Southeast RHR/CS corner room.
- HPCI room.

B. Each corner room communicates with the main volume through stairway openings of ~ 48 ft^2. The torus chamber room communicates with the main volume through ~ 6.7 ft^2 of air gap around the primary containment. The HPCI

room communicates with both the main volume and the southeast corner room through ~ 0.5 ft^2 of duct openings.

C. The SGTS takes a suction from the main volume and discharges to the main stack. An initial SGTS capacity of 4000 sf^3/min (1 of 2 redundant filter train units) is used.

D. Reactor building infiltration is equivalent to 1 volume change per day at 0.25-in. water column ΔP.

E. Each volume is at atmospheric pressure and design operating temperature at the beginning of the transient.

F. The heat loads to the various subcompartments following the LOCA are as follows:

1. The initial heat load in the reactor building volume above el 130 ft is due to emergency lighting. After a time delay, a second heat load term of 123,300 Btu/h is added to account for heat transfer through the 6-ft concrete biological shield. This term is based upon a drywell temperature of 200°F, which is assumed to remain constant.

2. The initial heat load to the torus chamber room is due to the heat from emergency lighting. A time-dependent torus heat load due to the postulated LOCA was developed from figures 6.2-11 and 6.2-23 and is included in the development of the transient.

3. The heat load in the CRD corner room is due to emergency lighting and pump operation.

4. The heat load in the RCIC corner room is due to emergency lighting and pump operation.

5. The heat load in the northeast and the southeast RHR/CS corner rooms is due to emergency lighting, plus operation of all pumps in the room.

6. The heat load in the HPCI room is negligible.

Table 6.2-9 provides a tabulation of the various heat loads in the secondary containment following a LOCA.

G. No heat transfer at the secondary containment structure boundaries was assumed in the analysis. The only heat transfer out of the secondary containment assumed in the analysis was due to:

- A slight amount of exfiltration when the volume was at a positive pressure early in the transient.

- The corner room coolers discussed in item J below.

H. The analysis results take into account both infiltration and exfiltration due to leakage. This is a realistic model based upon a conservative leakage rate of 915 ft^3/min. The analysis was also performed using the same methods as those described herein but taking into account only infiltration and neglecting exfiltration.

The results indicate that all compartments will become depressurized; i.e., the pressure is less than atmospheric pressure minus 0.25-in. water column in < 150 s.

It should be noted that the analysis results, assuming no exfiltration, are considered to be unrealistic values, representing an improbable situation. If infiltration into the building occurs when the pressure inside the building is less than atmospheric, exfiltration is most likely to occur when the inside pressure is greater than the atmospheric pressure.

I. The integrity of the secondary containment is maintained in accordance with the requirements specified in the Technical Specifications.

The annunciator response procedures in the plant procedures manual provide administrative controls for openings of the secondary containment. The interlocks prohibit the simultaneous opening of the inner and outer airlock doors.

J. Credit was taken for one cooler operating in each corner room at design capacity. The coolers are redundant and designed for post-LOCA operation. Paragraph 9.4.2.2.3 provides a more detailed description of the coolers. Table 6.2-9 provides a tabulation of the design heat removal capacity for these coolers.

K. All normal ventilation systems are lost at the time of the accident.

L. Offsite power is not available.

M. In the case of an LOSP, the SGTS is manually reset in the MCR, and 18 s elapse prior to SGTS operation (13 s for the emergency generators to energize the SGTS, plus 5 s to get to speed).

N. The SGTS fan has an initial capacity of 4000 sf^3/min with 13-in. water column static pressure. The fan capacity decreases as a function of suction pressure.

O. Pressure and temperature are uniform within each subcompartment; i.e., no local gradients within each subcompartment are assumed to exist.

P. The following high-energy lines penetrate the secondary containment:

- Four 24-in. main steam lines.

- Two 18-in. feedwater lines.
- Two 18-in. RHRSW lines.
- One 10-in. auxiliary steam line.

Analyses were performed to determine the response of the secondary containment to high-energy line breaks (HELBs). The analyses provided in supplements 15A and 15A.A demonstrate the design features provided to ensure the capability to safely shut down the plant following HELBs.

Using the above assumptions, an iterative calculational scheme was developed to determine the time-dependent containment response. The analysis incorporates the following model:

The initial mass and energy in each subcompartment are calculated on the basis of starting conditions of standard atmospheric pressure (14.696 psia) and the design operating temperature for the given subcompartment.

The mass of the air is obtained using the perfect gas law:

$$M = \frac{(144)(PC)(V)}{(R/n)(TC)}$$

where:

PC = pressure in compartment (lb/in.^{2})

V = free volume of compartment (ft^3)

R = gas constant (1545.3 ft-lb/lb-mol-°R)

n = molecular weight of air (28.97 lb/lb-mol)

TC = temperature in compartment (°R)

The internal energy of the air in the compartment is given by:

$$E = (CV)(M)(TC)$$

where:

CV = specific heat of air (0.171 Btu/lb-°F)

TC = temperature in compartment (°F)

In each increment of time, the heat energy added to the compartment from the assumed heat sources, the heat energy removed by the ECCS corner room coolers, and the mass and energy removed by the SGTS are calculated.

The heat sources included in the analysis are:

- The full wattage of all emergency lighting assumed to be transferred to the air as heat energy.
- The heat load due to ECCS pump operation conservatively assumed to be equal to the load used to size the corner room coolers.
- The heat load to the torus chamber room assumed to be a combination of convective and radiation heat transfer between the torus shell and the containment air.

The convective coefficient of heat transfer is conservatively calculated by:

$$h_c = 0.18\left(\Delta T\right)^{1/3}$$

where:

ΔT = temperature difference between torus shell and air.

The radiation heat transferred to the air is calculated by:

$$Q = \sigma \varepsilon A\left[\left(\frac{TT}{100}\right)^4 - \left(\frac{TA}{100}\right)^4\right]$$

where:

σ = Stefan Boltzman constant [0.171 Btu/(ft^2)(h)(R^4)]

ε = emissivity of torus shell (0.94)

TT = torus shell temperature (°R)

TA = air temperature (°R)

In both cases, the torus temperature is taken from figures 6.2-11 and 6.2-23.

The torus chamber room and the ECCS corner rooms are essentially subterranean. It is assumed all infiltration or exfiltration is from the main reactor building volume above el 130 ft.

Using the assumed 100% volume leakage per day at 0.25-in. water column, an equivalent leakage area is determined. Using the calculated leakage area, the building infiltration or exfiltration is calculated by:

$$q = \sqrt{\frac{2g_c\,\Delta P\,P}{T\,R}}\left(144\right)A$$

where:

q = rate of flow (lbm/s)

A = leakage area (ft^2)

g_c = acceleration of gravity (32.2 ft/s^2)

ΔP = differential pressure between containment and atmosphere ($lb/in.^2$)

P = atmospheric pressure or containment pressure if greater than atmospheric pressure ($lb/in.^2$)

T = atmospheric temperature or containment temperature if containment pressure is greater than atmospheric (°R)

R = gas constant for air $\left(5.3 \dfrac{ft - lb_f}{lbm - °R}\right)$

Using this equation, the mass flow between subcompartments is calculated from the previously calculated subcompartment pressure and temperature. A mass and energy balance for each subcompartment is made for a small increment of time; the final compartment pressure and temperature are calculated using the previous equations.

By reiterating the above calculations in the indicated sequence, using sufficiently small time increments, a conservative time-dependent secondary containment temperature and pressure response is obtained.

Results

The time-dependent temperature and pressure response of the secondary containment following the design basis LOCA is given in table 6.2-10. All compartments in the secondary containment become depressurized; i.e., with respect to ambient, the pressure is > -0.25-in. water column in < 120 s. Although the analysis does not extend beyond 1000 s following the LOCA, the analysis results for containment pressure continue to show it becoming more negative with respect to ambient pressure, and the results do not indicate the containment remains depressurized throughout the long term.

Secondary containment pressure decreases to a point where an equilibrium is established between the increased secondary containment infiltration rate, due to the higher ΔP, and the decreasing fan capacity resulting from the negative suction pressure.

6.2.4 STANDBY GAS TREATMENT SYSTEM

The SGTS is the ESF system for ventilation and cleanup of the primary and secondary containments in the event of certain anticipated operational occurrences or postulated DBAs.

The SGTS meets the design, quality assurance, redundancy, energy source, and instrumentation requirements for ESF systems.

6.2.4.1 Design Bases

6.2.4.1.1 Safety Design Bases

The SGTS is designed to:

- Limit the release of radioactivity to the environment following a DBA or leakage of radioactivity into the secondary containment or fuel handling area.
- Ensure leakage into the secondary containment from the outside by maintaining at least a 0.20-in. water negative pressure.
- Ensure all discharge from the primary or secondary containment or fuel handling area is through an elevated release; i.e., the main stack.
- Meet the following requirements of an ESF system:
    - Quality group classifications (B and C) in accordance with Regulatory Guide (RG) 1.26 (Revision 1, September 1974).
    - Seismic Category I requirements of RG 1.29 (Revision 1, August 1973).
    - Sufficient redundancy and separation to meet single-failure criteria and the requirements of IEEE-279-1971.
    - Ability to obtain power from the essential ac power system upon loss of normal ac power (offsite power).
    - Capability for periodic testing and inspection of principal system components.
    - Applicable quality assurance requirements.

6.2.4.1.2 Power Generation Design Basis

The SGTS also serves as a vent path for the manually initiated normal operation purging or venting of the primary containment. In the event any radioactivity exists in the primary containment at the time of purging or venting, the SGTS filters reduce the amount of radioactivity released.

6.2.4.2 System Description

The SGTS is shown schematically in drawing no. H-26078. Principal system components are listed and described in table 6.2-14.

The SGTS automatically filters the exhaust air from the reactor building and/or the fuel handling area following an accident.

As an alternate mode of operation, the drywell and/or torus purge exhaust are manually directed to the SGTS for processing before release up the main stack.

The SGTS consists of two identical, redundant, parallel air filtration assemblies separated by a 4-ft 6-in.-thick concrete wall and are completely enclosed within a Seismic Category I structure. Each filtration assembly and its respective components are designed for 100% capacity operation. Each filtration assembly consists of the following components (listed in the order of the direction of airflow):

- Demister or moisture separator to reduce absolute humidity.
- Electric heater for relative humidity control to maintain adsorbtion efficiency of the carbon bed. (Note: The heater operation is not credited and is maintained for defense-in-depth.)
- Prefilter for removal of larger particulates to protect the high-efficiency particulate air (HEPA) filter.
- HEPA filter for removal of particulate matter as small as 0.3 mm and larger.
- A 4-in. deep-bed impregnated-carbon adsorber to remove gaseous elemental iodine and methyl iodide.
- Final HEPA filter for removal of postulated particulate matter the air stream can carry off the carbon adsorber.
- Exhaust fan to move the air.

With the reactor building isolated, each of the two exhaust fans has the necessary capacity to reduce to and hold the reactor building at a minimum negative pressure of 0.20-in. water.

Pressure sensors monitoring the secondary containment pressure during SGTS testing are located as indicated below and shown on drawing no. H-26098.

ΔP Transmitter Tag No.	Pressure Sensor Locations: Inside Sensor and Transmitter	Pressure Sensor Locations: Outside Sensor
2T46-DPT-N005 B	East wall of reactor bldg at el 130 ft at coordinates R17-RL	Reactor bldg roof
2T46-DPT-N005 C	East wall of reactor bldg at el 130 ft at coordinates R23-RL	NA

A pressure-temperature analysis of the secondary containment demonstrated the pressure throughout the secondary containment is nearly uniform and no regions of exfiltration exist following the establishment of a negative pressure by the SGTS. Therefore, the regions monitored by the pressure sensors are typical regions and adequately identify regions of potential exfiltration.

To provide accurate ΔP measurements between the secondary containment and the outside atmosphere during SGTS testing, the outside sensing lines are routed along the outside wall to the roof of the HNP-2 reactor building. Each sensing line from both transmitters is fitted with diffusers that reject any effect wind velocity would have on the sensing lines monitoring either the inside or the outside atmospheres. Since the outside sensors monitor the atmosphere on the roof of the reactor building and are clear of nearby obstacles, nonuniform wind loadings are not a factor.

Each filtration assembly train has a design maximum flowrate of 4000 ft^3/min for drawdown purposes. When a high-pressure drop across the filtration subassembly is alarmed within the MCR, the operator manually initiates the redundant filter train.

The prefilter is rated at 90% efficiency in accordance with ASHRAE Standard 52-76. The HEPA filters are rated at 99.95% efficiency for particulate matter 0.3 mm and larger. The carbon adsorber is rated at 97.5% methyl iodide removal efficiency at conditions of 30°C and 95% relative humidity.

Small cross connections between the filter assemblies maintain required decay heat removal cooling airflow on the charcoal beds in the inactive filter assembly.

Any accident condition in either HNP-1 or HNP-2 (LOCA, reactor building high radiation, or refueling floor high radiation) starts both trains of the HNP-1 and HNP-2 SGTSs. This design feature allows more SGTS capacity to be available for draw down of all essential areas in both units to a subatmospheric pressure in order to contain the product of the radiological accident. The number and combinations of SGTS trains required to draw down the various secondary containment types are given in the Technical Requirements Manual (TRM). The two trains of the HNP-2 SGTS can also be manually operated from the MCR.

Each assembly discharges to the main stack through a separate Seismic Category I underground line.

Redundant excess flow isolation dampers, in series, are provided on the containment purge and vent line downstream of the purge valves and before the SGTS filter trains. The purpose of

these isolation dampers is to prevent high LOCA pressure from overpressurizing the filter trains in the unlikely event of a LOCA during containment venting. A 2-in. bypass line around the dampers ensures a vent path is available at all times.

In accordance with the requirements of NRC Generic Letter 89-16, "Installation of a Hardened Wetwell Vent," venting the torus in the event of a loss of long-term decay heat removal sequence can be accomplished by bypassing the low pressure SGTS filter trains. This vent capability (drawing nos. H-26078 and H-26084) can be utilized for severe accident situations and is not intended for normal operation or design basis accident mitigation.

6.2.4.3 Instrumentation Application

Differential pressure indicators measure the pressure drop across each filter and the charcoal bed. The overall pressure drop across each complete filtration train is measured and alarmed in the MCR upon high ΔP.

Each charcoal adsorber has six temperature switches. A signal from any of the switches can actuate an alarm in the MCR and isolate the filter. The deluge system is manually activated as needed.

The electric air-heating coil is electrically interlocked with the SGTS fan such that the heater is activated whenever the fan is operated (air flow switch activated). A manual auto-off switch enables deactivation of the heater during surveillance testing of the SGTS filter train. A temperature controller upstream of the carbon adsorber cuts off the electric heating coil upon indication of high temperature.

Radiation monitors in the refueling floor ventilation exhaust duct indicate a fuel-handling accident and automatically initiate the SGTS. Additional radiation detectors are provided on the discharge of each filtration assembly and in the main stack for monitoring purposes.

Instrumentation for automatic initiation of the SGTS following a postulated LOCA is described in subsection 7.3.6.

Flow switches for each assembly train initiate an alarm in the MCR upon loss of flow. In addition, each of the two SGTS discharge lines is provided with a flow element and transmitter to indicate and record in the MCR the flow through the line.

6.2.4.4 Safety Evaluation

A single-failure analysis is provided in table 6.2-15. Testing and inspection ensure quality and performance of the equipment and are discussed in paragraph 6.2.4.5.

The SGTS is fully redundant and capable of performing following a single failure. In the event of an LOSP, the SGTS fans can be powered from the emergency service portions of the auxiliary power distribution system. The fan associated with each filter assembly is powered from a different emergency diesel in the event of an LOSP. The system includes isolation dampers

that fail open on loss of power to the solenoids or upon loss of instrument air to the air operators on the dampers. An interlock with the associated exhaust fan prevents the heating coil from operating when the fan is shut down. The system components and ductwork meet Seismic Category I requirements.

In the event of an automatic initiation signal for the SGTS, the normally operating reactor building and refueling floor ventilation systems are isolated. Since other boundary penetrations, such as access doors or electrical cables, are normally sealed, the only potential fission product release path is through the SGTS to the main stack. Since infiltration is the only path for replacement air, negative pressure is maintained within the SGTS suction boundaries.

The main stack provides an elevated release point for airborne activity during the postulated loss-of-coolant and fuel-handling accidents. Release of activity to the environs from the SGTS is analyzed in detail in section 15.3.

When a potential fire is detected by the rise in temperature within the carbon adsorber, the deluge system is manually activated by connecting a local fire hose to the fire protection water piping. An angle valve is opened on each side of the hose connection and a gate valve is opened to the affected unit, allowing water to flow to the nozzle network inside the SGTS plenum. The system continues in this mode until shut down manually. To ensure against a radioactivity release as the result of the water deluge, the dampers automatically isolate the filters.

6.2.4.5 Tests and Inspections

The SGTS and its components are thoroughly tested in a program consisting of the following test types:

- Predelivery tests and component qualification to ensure the quality of the manufactured product.
- Post-installation acceptance tests to ensure proper installation and operability, as well as detect damage in shipping, storage, and handling.
- Normally operating surveillance tests to detect equipment failure and evaluate the effects of normal operation on parameters such as filter pressure drop.

Written test procedures establish the minimum acceptable values for all the test types. All test results are recorded as a matter of performance records, thus enabling early detection of faulty performance.

The predelivery and component qualification tests were generally in accordance with the recommendations and guidelines provided in NRC RG 1.52 (June 1973), Section C.3, "Component Design Criteria and Qualification Testing." Normally operating surveillances are performed in accordance with applicable sections of RG 1.52, Revision 2 (March 1978). HEPA filters have a minimum efficiency of 99.95% when measured with 0.3-mm dioctyl phthalate

(DOP) aerosol. Carbon lot testing is performed and certified by a qualified testing agency to establish the following:

- Uniformity of density.
- Ignition temperature.
- Hardness.
- Impregnant content.

Fans were tested in accordance with AMCA Standard 210, "Air Moving and Conditioning Association Test Code for Air Moving Devices," to establish characteristic curves. Dampers, valves, and operators were tested to demonstrate effectiveness of seal, operating time, and ability of the actuator to perform under the maximum anticipated conditions of ΔP.

The post-installation acceptance tests are generally performed in accordance with the applicable guidelines of RG 1.52, Revision 2 (March 1978), Section C.5, "In-Place Testing Criteria." The tests include the following:

- Visual inspection.
- Housing leak test.
- Airflow capacity verification test.
- Airflow distribution verification test across the HEPA filters.
- Adsorber bed residence time verification test.
- Air aerosol uniformity test.
- In-place adsorber test.
- Laboratory test of adsorbent.
- Electric heater test.

If acceptability requirements for predelivery, post installation, or surveillance tests are not met, only exact replacement or approved and documented repairs are made.

Periodic in-place testing of HEPA filters and charcoal adsorbers, laboratory testing of charcoal adsorbers, and performance testing of the SGTS's capability to draw down the secondary containment in the required time period assumed in the analysis in section 15.3 are performed in accordance with the Technical Specifications.

6.2.5 CONTAINMENT ISOLATION SYSTEM

6.2.5.1 Safety Design Bases

A. Containment isolation valves provide the necessary isolation of the containment in the event of accidents or other conditions when the free release of containment contents cannot be permitted.

B. The design of isolation valving for lines penetrating the containment follow the requirements of General Design Criteria (GDCs) 54 through 57 to the greatest extent practicable, consistent with safety and reliability.

C. Isolation valving for instrument lines that penetrate the containment conform to the requirements of RG 1.11 (March 1971), with minor exceptions listed in paragraph 6.2.5.3.3.

D. Isolation valves, actuators, and controls are protected against damage by missiles.

E. Design of the containment isolation valves and associated piping and penetrations is Seismic Category I.

F. Containment isolation valves and associated piping and penetrations meet the requirements of the ASME Code, Section III, Classes 1, 2, or 3, as applicable.

6.2.5.2 System Description

The basic function of all primary containment isolation valves is to provide necessary isolation to the containment in the event of accidents or similar critical conditions when the release of containment atmosphere cannot be permitted. ***TRM table T7.0-1 (incorporated by reference into the FSAR)*** lists the containment isolation valves, defines valve status (normally open or normally closed) during normal reactor operation, and shows the signals required to initiate desired operation. ***TRM table T7.0-1*** also identifies all fluid system and fluid instrument lines that penetrate the primary containment and all branch lines that require isolation. Piping and instrumentation diagrams of the systems that penetrate the containment are identified in chapters 5, 7, and 9. The referenced diagrams indicate the location of the isolation valves with respect to the containment.

Leak detection and leak detection systems (LDSs) are described in subsections 5.2.7, 7.3.2, and 9.3.3. The use of the LDSs incorporated with normal plant operating procedures is the method used by plant operators to isolate the remote manual containment isolation valves.

All relief valves used as containment isolation valves are located outside the primary containment and are arranged so they discharge toward the primary containment. The piping to the inlet of the relief valve is not a part of the primary containment boundary. The relief valves that discharge to the primary containment are as follows:

Valve No.	Set Pressure
2E11-F025A,B (thermal relief)	358°F/400 psig
2E11-F029 (thermal relief)	358°F/200 psig
2E11-F097	85 psig
2E11-F055A,B	450 psig

Section 3.1 describes conformance to GDC 6, Primary Containment Isolation. Justification for penetrations that do not conform to GDC 56 is also given in section 3.1.

Physically independent motor power sources for series valves on process lines requiring two valves are provided so that no single active failure can interrupt motive power to either closure device. Upon loss-of-valve actuation power and when containment closure action of the valve is called for, the valve fails closed. Loss of valve actuation power is detected and annunciated in the MCR.

MSIV closure time is such that for any design basis break, the coolant loss is restricted so that the reactor core is not uncovered.

Traversing incore probe (TIP) subsystem guide tubes are provided with an isolation valve that closes automatically upon receipt of a proper signal and after the TIP cable and fission chamber have been retracted. In series with this isolation valve is an additional or backup isolation shear valve. Both valves are located outside the drywell. The function of the shear valve is to ensure integrity of the containment even in the unlikely event that the other isolation valve should fail to close or the chamber drive cable should fail to retract if it is extended into the guide tube during the time containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon an actuation signal. Valve position (full open or full closed) of the automatic closing valves is indicated in the MCR. Each shear valve is operated independently. The valve is an explosive-type valve, dc-operated, with monitoring of each actuating circuit provided. The shear valves are manually initiated.

In the event of a containment isolation signal, the TIP subsystem receives a command to retract the traveling probes for the mechanisms. Upon full retraction, the isolation valves are closed automatically. If a traveling probe becomes jammed in the tube run such that it cannot be retracted, the plant operator can determine if the shear valve should be operated based upon instrument indication.

Each motor-operated valve (MOV) is provided with limit switches that are used to indicate that the valves are either open or closed. Each MOV is capable of being actuated from the MCR.

Section 3.11 discusses the environmental conditions, both normal and accidental, for which the containment isolation valve system is designed. The section also discusses the qualification tests required to ensure the performance of the isolation valves under those environmental conditions.

All containment isolation valves are located either inside the primary containment or inside the reactor building (secondary containment). Both structures are of Seismic Category I design and are protected against damage from missiles. A discussion of the turbine missile design criteria for these structures is provided in section 3.5.

Containment isolation valves are designed in accordance with the requirements of the ASME Code, Section III. Where necessary, a dynamic system analysis that includes the impact effect of rapid valve closures under operating conditions is included in the design specifications of piping systems that require containment isolation valves. Vibration operational testing, discussed in section 3.9, is conducted during plant startup.

6.2.5.3 Safety Evaluation

6.2.5.3.1 Introduction

The main objective of the containment isolation system is to provide protection by preventing releases of radioactive material to the environment. This is accomplished by complete isolation of system lines penetrating the containment. Redundancy is provided in all design aspects to satisfy the requirement that any failure of a single valve or component does not prevent containment isolation.

The isolation valves have redundancy in the mode of actuation with the primary mode being automatic and the secondary mode being remote-manual. A program of testing, described in paragraph 6.2.5.4, is maintained to ensure valve operability and leaktightness. The design specifications require each isolation valve to be operable under the most severe operating conditions that it might experience. Each isolation valve is afforded protection by separation and/or adequate barriers from the consequences of potential missiles.

Electrical redundancy is provided in isolation valve arrangements, eliminating dependency upon one power source to attain isolation. Electrical cables for isolation valves in the same line are routed separately. Cables are selected and based upon the specific environment to which they may be subjected, such as potential magnetic fields, high radiation, high temperature, and high humidity.

Provisions for administrative control and/or locks ensure that the position of all nonpowered isolation valves is maintained and known. For all power-operated isolation valves the position is indicated in the MCR. Discussion of instrumentation and controls for the isolation valves is included in chapter 7.

6.2.5.3.2 Evaluation Against NRC Criteria

Evaluation of the containment isolation system against GDCs 54, 55, 56, and 57 is discussed in section 3.1.

6.2.5.3.3 Evaluation Against Regulatory Guide 1.11

The design and installation requirements for all instrument lines between their containment isolation valves and the sensors are the same as for the process lines to which they attach. The classifications of the process pipes are provided in section 3.2. All instrument lines connected to the reactor coolant pressure boundary (RCPB) are Seismic Category I and quality group A up to and including the last containment isolation valve. All such instrument lines from the last isolation valve to the sensor are quality group B. Instrument lines are generally stainless steel; however, in some cases, lines have stainless-steel and carbon-steel sections. Visual inservice inspection for all quality group A portions of these lines is possible.

Maximum practicable separation is provided for redundant instrument lines and combined with protection; the failure of one line does not induce failure in another. The response times for all sensors connected to instrument lines are not affected by the valves or orifices in the lines.

The design and installation of instrument lines are in conformance with RG 1.11 (March 1971), with the minor exceptions discussed in the following paragraph.

6.2.5.3.3.1 Instrument Lines Connected to RCPB. The instrument sensing lines listed below penetrate the primary containment and connect to the RCPB. All lines are equipped with a restriction orifice located as close as is practical to the point of connection to the RCPB inside of the primary containment. A manual shutoff valve is located on the outside of the primary containment and is installed as close as is practical to the point of exit. Immediately downstream of the manual valve is an excess flow check valve that automatically closes for a line break downstream of the valve. Indicating lights on a MCR panel monitor valve position. The valve may be reopened by action of a solenoid attachment that is operated from the panel after repairs are made. This system fulfills the requirements of RG 1.11 (March 1971). No instrument lines penetrate both the primary and the secondary containments.

- 16 lines for measurement of main steam flow.
- 24 lines for jet pump flow measurement.
- 9 lines for RPV water level and pressure measurement.
- 8 lines for measurement of recirculation pump discharge flow.
- 8 lines for jet pump header ΔP measurement.
- 4 lines for measurement of ΔP across recirculation pumps.
- 4 lines for measurement of recirculation pump seal pressures.
- 4 lines for measurement of core ΔP and reference for jet pump flow.
- 4 lines for steam LDS for the HPCI turbine steamline.

- 4 lines for steam LDS for the RCIC turbine steamline.
- 2 lines for measurement of recirculation pump B suction pressure.
- 2 lines for CS header ΔP measurement.

The postulated failure of an instrument line from the RCPB is discussed and evaluated in section 15.4. The leakage from such a rupture upstream of the excess-flow check valve is minimized by the 1/4-in. restricting orifice in the line. This event does not impair the integrity and functional performance of the secondary containment and SGTS, and the calculated potential offsite exposures are substantially below the guidelines of 10 CFR 100. The loss of coolant from such a break is inconsequential when compared to the makeup capabilities of the feedwater or RCIC system.

6.2.5.3.3.2 **Instrument Lines Connected to Primary Containment Atmosphere.** Six lines that penetrate the primary containment are used to measure the hydrogen and oxygen content of the primary containment atmosphere. These lines have two air-operated isolation valves outside the containment downstream of a manual shutoff valve. An exception to RG 1.11 (March 1971) is taken here, since both isolation valves are located outside the containment; however, installation of a valve inside the containment would reduce the reliability of the system whose purpose is to monitor the containment atmosphere during and after an accident. The isolation valves have automatic isolation that can be overridden by operator action to permit monitoring of the containment atmosphere. These valves can be remotely closed by manual action from the MCR. Valve position indication is also provided in the MCR.

The fission products monitoring system uses two lines that penetrate the primary containment and conform to RG 1.11 (March 1971). Each line is provided with two air-operated isolation valves located outside the containment downstream of a manual shutoff valve. These valves are closed automatically during and after an accident but can be manually overridden to permit monitoring of the containment atmosphere. The valves can be remotely operated by manual action from the MCR. Indication lights in the MCR show valve positions.

One line with two manual shutoff valves located outside the containment is connected to the torus for fission products monitoring.

Two lines connected to the torus and six lines connected to the drywell measure containment pressure. Four more lines connected to the torus measure water. In each of these lines, one manual isolation valve is located outside containment, and one remotely operated (from the MCR) valve is located downstream of the manual valve. Each of the remotely operated valves is a fail-as-is-type with remote position indication in the MCR. An exception to RG 1.11 (March 1971) is taken for these lines, since they are needed to measure significant parameters during and after an accident.

6.2.5.3.3.3 **Other Instrument Lines.** Twelve lines that conform to RG 1.11 (March 1971) penetrate the torus shell to supply air to piston operators on the vacuum breaker valves. These

lines neither penetrate the RCPB nor open to the primary containment atmosphere. One solenoid valve for each line is located close to the penetration outside the torus shell. The valves are manually controlled from the MCR where position indication is also provided.

6.2.5.4 Tests and Inspections

To ensure the integrity of the containment isolation system, preoperational testing and inservice surveillance testing are performed on the containment isolation valves, containment penetrations, and control systems for initiating isolation.

Paragraph 3.8.2.8 describes the leak testing of the containment and containment isolation valves, and subsection 7.3.2 describes the testing of the containment system control and instrumentation systems.

In addition, an inservice inspection program for the containment isolation valves that are part of the RCPB is described in subsection 5.2.8.

6.2.5.5 Materials

The materials of construction of the containment isolation system are discussed in the applicable system chapters; i.e., chapter 5, 7, or 9. No materials that yield radiolytic or pyrolytic decomposition products that can interfere with the safe operation of this or any other ESF are present in the containment isolation system.

6.2.5.6 Control of Combustible Gas Concentrations in Containment Following a LOCA (HNP-1 and HNP-2)

Following a LOCA, hydrogen and oxygen are evolved within the primary containment from two sources, postulated zirconium metal-water reactions in the core and radiolysis. The only additional source of oxygen that may be postulated for a boiling water reactor (BWR) containment system is derived from the small amount of dissolved and free oxygen in the reactor water and steam. If all the oxygen from this source potentially available to the containment becomes free, the contribution to an inert containment with ~ 4.0% oxygen is insignificant. This source was discussed in the response to question G7.31 on Duane Arnold Docket No. 50-331. Safety Guide 7 contains parameters to be used for "evaluating the production of combustible gases following a LOCA" (table 6.2-11). Dresden Special Report No. 14 and other dockets show these assumptions are very conservative. Nonetheless, the CAD system design basis observes the restrictions and limits contained in Safety Guide 7.

Since Safety Guide 7 was published in March 1971, various solutions that may resolve the problem of hydrogen control were considered. The CAD system controls the combustible gases within the containment by simply diluting the combustible gases. Thus, the combustible gases always remain below their flammability limit. It was determined, in accordance with the guidance provided in Safety Guide 7, that this type of containment atmosphere dilution

operation is an acceptable method of controlling the combustible gas concentrations within the containment following a LOCA.

Safety Guide 7 specifies the flammability limit for hydrogen and oxygen as 4.0 and 5.0 volume percent (v/o), respectively. That is, the hydrogen concentration should not exceed 4.0 v/o if more than 5.0 v/o oxygen is present, and the oxygen concentration should not exceed 5.0 v/o if more than 4.0 v/o hydrogen is present. Either the hydrogen concentration or the oxygen concentration must be controlled to within these flammability limits. Further use of Safety Guide 7 for a zirconium metal-water reaction event shows that inerting of the containment is required to prevent a flammable mixture as the rapid metal-water reaction occurs. The more slowly evolved hydrogen and oxygen from radiolysis can be limited to less than flammable mixture by limiting the oxygen concentration. Limiting the oxygen concentration can be accomplished by adding nitrogen to the containment atmosphere, thus diluting the oxygen concentration to less than the flammability limit.

The oxygen level in the inerted containment during normal operation is maintained at < 4.0% by volume. Following a LOCA, radiolysis begins to form more oxygen. By adding nitrogen to the containment as the radiolytic formation of oxygen occurs, the oxygen is diluted and remains below the flammability concentration of 5.0% by volume. Since the radiolysis rate decreases with time as a result of fission product decay, the required nitrogen addition rate will also decrease with time.

Thus, the containment atmosphere dilution consists of simply adding nitrogen to the containment to dilute the oxygen concentration to below the oxygen flammability limit. The containment pressure increases due to the addition of nitrogen but is limited or controlled by normal containment leakage. The CAD operation is manually controlled from the MCR. The nitrogen addition rate is controlled and monitored from the MCR. Additional nitrogen for long-term operation can be obtained and connection to the nitrogen makeup system can be readily accomplished. The nitrogen inerting system is shown on P&ID H-16000 (HNP-1) or H-26083 (HNP-2). Normal monitoring of oxygen levels in the drywell is accomplished by use of a commercial-grade oxygen analyzer, 1P33-P006 (HNP-1) or 2P33-P006 (HNP-2). Normal monitoring of oxygen levels in the torus is accomplished by use of the post-accident hydrogen and oxygen analyzing system. The post-LOCA containment atmosphere is monitored for combustible gas accumulation by redundant hydrogen and oxygen monitoring systems for the drywell and torus as discussed in paragraph 6.2.5.6.2.

An evaluation of the effects of thermal power optimization (TPO) to 2818 MWt was performed using Safety Guide 7 criteria and the latest fuel design data. Based upon the conservative hydrogen and oxygen production assumptions of Safety Guide 7, the table below summarizes the time required to reach a 4.0 v/o or a 5.0 v/o oxygen concentration without operation of the CAD system:

Post-LOCA CONDITION ANALYZED	CTMT LOCATION	UNIT 1	UNIT 2
Time to reach 5.0 v/o O_2 (without CAD)	Torus	3.6 days	3 days
	Drywell	4 days	3.2 days
Time to reach 4.0 v/o O_2 (without CAD)	Torus	1.51 days	1.33 days
	Drywell	2.10 days	1.85 days

Manual override of system isolation and initiation of nitrogen addition takes place from the MCR at or before the 5.0 v/o oxygen concentration to ensure a nonflammable containment atmosphere.

For conservatism, the TPO analysis used an oxygen concentration control limit of 4.0 v/o rather than 5.0 v/o. The oxygen concentration can be limited to 4.0 v/o if the CAD system is turned on when the oxygen concentration reaches 4.0 v/o with a constant flowrate of 30 sf^3/min to both the drywell and torus. The modeled CAD flowrate of 60 sf^3/min (2 x 30 sf^3/min) is well within the 100 sf^3/min design capacity of the CAD system.

With a constant CAD flowrate of 30 sf^3/min for both the drywell and the torus, and no containment leakage modeled, containment pressure exceeds 28 psig; i.e., 50% of design or ~ 43 psia, in about 5 days. In reality, the required CAD flowrate will decrease with time and the pressure rise will be more gradual. Containment purging or venting can be used for pressure relief. Plant emergency operating procedures specify containment purging/venting requirements for pressure control in conjunction with the CAD system.

The containment sample time response of the hydrogen and oxygen analyzer instruments to be supplied is adequate to allow the operator time to act. The nitrogen addition is done on a step basis. Redundant containment pressure, oxygen and hydrogen sensors are available to continuously monitor containment conditions.

To operate the CAD system, the operator opens two isolation valves to the drywell or two isolation valves to the torus or both. The operator can dilute either the drywell or the torus using a flow indicator controller. Valve position indicating lights are provided in the MCR.

With the containment inerted and maintaining the oxygen concentration < 4.0% during normal operation, the only factor tending to deinert is the radiolytic formation of oxygen. In containment with a free air volume of ~ 259,000 ft^3 (HNP-1) or ~ 256,100 ft^3 (HNP-2), the addition of this small amount of oxygen from a dispersed source cannot cause local nonuniformity of oxygen concentration greater than a small fractional percentage. There are many driving forces for mixing in the containment. Diffusion, the one mixing driving force that can be calculated, is sufficient to ensure the maximum oxygen concentration deviation from the average does not exceed 0.015%. The details of this analysis can be found on Duane Arnold Docket No. 50-331. Both torus and drywell sprays can be activated periodically to provide a thorough mixing mechanism.

Sufficient dilution nitrogen is present onsite to provide approximately 7 days of CAD post-LOCA operation, an adequate time to ensure control of combustible gases until additional offsite nitrogen supplies are available. For the case where no credit is taken for steam and zirconium metal-water hydrogen dilution, the time required to reach 5.0 v/o oxygen concentration limit is summarized below:

Post-LOCA CONDITION ANALYZED	CTMT LOCATION	UNIT 1	UNIT 2
Minimum time to reach 5.0 v/o O_2 (No credit is taken for steam and metal-water hydrogen dilution)	torus	8.7 h (0.361 days)	8 h (0.333 days)
	drywell	12 h (0.5 days),	13 h (0.54 days

This is the absolute minimum time at which the CAD system must be actuated.

Redundancy of the nitrogen supply is assured by two independent lines having separate valves, instruments, and electrical power. CAD subsystem A is supplied from the Unit 1 nitrogen storage tank and CAD subsystem B is supplied from the Unit 2 nitrogen storage tank. Thus, if any one supply line fails, the other line is available.

Two redundant Seismic Category I lines are manually isolable from any failed Seismic Category II portion of an associated subsystem by means of the block valves.

The components of the nitrogen addition system are designed such that failure of any one active item neither affects the containment integrity nor introduces any safety problems. Seismic design and quality assurance for critical components necessary to maintain system function and boundary under a Seismic Category I occurrence are maintained. Redundancy is ensured by providing two systems for supply and venting. Control power supplies for the isolation valves are taken from separate safeguard emergency sources.

CAD operation does not result in an increased exposure to the public over that calculated and presented in the FSAR. HNP-2-FSAR section 15.3 provides offsite radiation exposure to the public for the design basis LOCA. In calculating the radiation exposures, a containment leakage rate of 1.5% (1.2% by weight) per day, which remains constant over the 30-day period following the accident, is assumed. If this leakage is present during CAD operation, the resulting exposure is the same as the exposure presented in HNP-2-FSAR section 15.3.

In addition, an evaluation of the incremental radiological effects of containment venting was performed assuming the primary containment is completely exhausted of all remaining activity during a 7-day period starting 30 days after the LOCA. (Note that venting is not required for pressure control at that time based upon evaluations performed in accordance with the parameters specified in table 6.2-11.) The incremental radiological effects of controlled containment venting, as defined, are small in relation to the reported radiological effects assuming 1.5% (1.2% by weight) per day containment leak rate without venting.

Corrosive containment sprays and emergency cooling solutions as a potential source of hydrogen were considered and were determined to be negligible, thus are not used. In any case, oxygen is controlled by nitrogen dilution.

6.2.5.6.1 Containment Purge (HNP-1 and HNP-2)

This containment purging system provides a backup method for controlling the containment gases in the unlikely event that the CAD operation does not perform properly. Piping and

valves connect the containment atmospheres to the SGTS to reduce fission product activity. These valves and associated piping are designed to Seismic Category I requirements. The SGTS removes fission product particulate and halogen activities prior to releasing the gases to the environment. Since purging is initiated under the operator's control and the effluent from the SGTS is monitored for radioactivity, the incremental dose at the low population zones due to purging is controlled to ensure the purge dose does not cause the total dose (LOCA plus purge dose) to exceed the limit specified in 10 CFR 50.67.

The purge system for the primary containment is not specifically designed for combustible gas control. However, HNP-1 and HNP-2 have the capability to purge the containment through the SGTS by way of two 2-in. lines off of 18-in. piping at el 193 ft 9 in. (HNP -1) or at el 194 ft (HNP-2) in the drywell and either of two 2-in. lines in the top region of the suppression chamber. All these lines are shown on drawing H-16024 (HNP-1) and H-26084 (HNP-2).

The torus purge vent line containing isolation valves 1T48-F318 and 1T48-F326 (HNP-1) or 2T48-F318 and 2T48-F326 (HNP-2) is the vent path from the torus for the torus hardened vent as shown on drawing H-16024 (HNP-1) and H-26084 (HNP-2). The torus hardened vent can be utilized for severe accident situations and is not intended for normal operation or DBA mitigation.

6.2.5.6.2 <u>Instrumentation Application</u> (HNP-1 and HNP-2)

6.2.5.6.2.1 Hydrogen and Oxygen Monitoring

The hydrogen and oxygen analyzer system consists of two separate, redundant systems, each capable of analyzing the hydrogen and oxygen content from the drywell or suppression chamber. Each hydrogen and oxygen analyzer channel is operated in parallel from separate penetrations in the drywell and the torus. The CAD monitoring (hydrogen/oxygen monitoring) operation is designed to be manually initiated from the MCR after containment isolation has occurred. The primary containment hydrogen/oxygen monitoring system is shown on drawing nos. H-16276 and H-16280 (HNP-1) or H-26048 and H-26049 (HNP-2).

The hydrogen and oxygen analyzing system is an engineered safety features (ESF) system and is designed in conformance with IEEE-279, 323-1974, and 344-1975 requirements. The hydrogen and oxygen analyzers form a closed system outside the containment. Resetting the ESF actuation signal allows the primary containment isolation valves for the system to be reopened and provides the capability to monitor the primary containment atmosphere. The redundant analyzer systems are contained in separate identical panels supplied by separate power sources. Each panel assembly is Seismic Category I qualified. The hydrogen analyzer is a dual-range device capable of measuring the ranges of 0 to 10 and 0 to 50 v/o hydrogen. The oxygen analyzer is a dual-range device capable of measuring the ranges of 0 to 10 and 0 to 30 v/o oxygen. Hydrogen and oxygen concentrations in the containment are continuously recorded in the MCR following a LOCA. This system is designed to be completely operable from two areas, at the local analyzer panel and in the MCR. An oxygen concentration of 3.5 v/o or higher and a hydrogen concentration of 2.5 v/o or higher in the torus or primary containment, as measured by the analyzer, are annunciated in the MCR.

The following is a more detailed description of the hydrogen and oxygen monitoring system:

A. Hydrogen Analysis

The measurement of hydrogen in the presence of nitrogen, oxygen, and water vapor is possible because the thermal conductivity of the hydrogen is approximately seven times higher than nitrogen, oxygen, and water vapor, which have nearly the same thermal conductivities (at the filament operational temperature of ~ 500°K). The measurement is accomplished by using a thermal conductivity cell and a catalytic reactor.

The sample first flows through the sample side of the cell, then passes through the reference side that includes the catalyst. The sample composition is determined by the difference in thermal conductivities between the sample side and catalyzed reference side of the cell.

Oxygen is provided ahead of the hydrogen analyzer for recombining the hydrogen. The amount of oxygen added is determined by the highest range of the analyzer.

B. Oxygen Analysis

The same technique and equipment used for measuring hydrogen are also used for measuring oxygen, except that an excess of hydrogen must be supplied to complete the reaction of all available oxygen in the sample.

The hydrogen and oxygen analyzer is qualified to operate under the environmental conditions that exist in the area where equipment is installed as a result of a LOCA. In addition, the analyzer is seismically qualified so that it performed before, during, and after all the vibration tests.

The hydrogen analyzer samples the atmosphere at el 172 ft 6 in. and 193 ft 9 in. (HNP-1) or el 143 ft 0 in. and 191 ft 6 in.(HNP-2) in the drywell and at two locations in the top portion of the suppression chamber. As discussed in paragraph 6.2.5.6, evolved hydrogen mixes uniformly to produce a homogeneous atmosphere in the drywell and the torus. The relatively small containment has no compartments in which hydrogen can collect without mixing.

The addition of hydrogen and oxygen gas bottles as calibration and reagent gas supplies for hydrogen and oxygen analyzer panels 1P33-P001A and B (HNP-1) or 2P33-P001A and B (HNP-2) to el 158 ft of the reactor building introduces a potential combustion/explosion hazard into this plant area. Design and administrative measures provided to reduce the potential for combustion and explosion are described in the ***Edwin I. Hatch Fire Hazards Analysis and Fire Protection Program (incorporated by reference into the FSAR)***.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

Edwin I. Hatch Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

REFERENCES

1. Joint GE and PG&E Report, "Pressure Suppression Test Program, Appendix I, Preliminary Hazard Summary Report, Bodega Bay, Atomic Park, Unit 1," December 1962.

2. "Elimination of the High Suppression Pool Temperature Limit for Plant Hatch Units 1 and 2," EAS-19-0388, General Electric, dated March 1988.

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

4. "Maximum Discharge Rate of Liquid-Vapor Mixtures from Vessels," NEDO-21052, General Electric Company, September 1975.

5. "The General Electric Pressure Suppression Analytical Model," NEDO-10320, General Electric Company.

6. "General Electric Model for LOCA Analysis in Accordance With 10 CFR 50, Appendix K," NEDE-20566P-A, General Electric Company, September 1986.

7. "The General Electric Mark III Pressure Suppression Containment System Analytical Model," NEDO-20533, General Electric Company, March 1971.

8. "Generic Guidelines for GE Boiling Water Reactor Extended Power Uprate," NEDO-32424P, General Electric Company, February 1995.

9. "Mark I Containment Program Plant Unique Load Definitions, Edwin I. Hatch Nuclear Plant," NEDO-24570, General Electric Company, March 1982.

10. "Mark I Containment Program Plant Unique Load Definition Edwin I. Hatch Nuclear Plant: Unit 2," NEDO-24569, Revision 2, General Electric Company, September 1981.

11. "Mark I Containment Program Load Definition Report," NEDO-21888, Revision 2, General Electric Company, November 1981.

12. Schneider, P. J., "Temperature Response Charts," John Wiley and Sons, New York, 1963.

13. Cook, K. W., "Preliminary Design Guide for Evaluation of Containment to Drywell Vacuum Relief Requirements for Mark III Containments," APED, SCER-297, Class II, NEDM-11013-125, 1973.

14. Deleted.

15. Deleted.

16. Brown, Ralph, and York, J. Louis, "Sprays Formed by Flashing Liquid Jets," A.I.Ch.E. Journal, p 149, May 1962.

17. Schrock, V. E. and Yao, Shi-Chune, "Heat and Mass Transfer from Freely Falling Drops," ASME publication, 75-WA/HT-37, July 28, 1975.

18. Pita, E. G., "Heat and Mass Transfer in Evaporating Sprays," PhD thesis, University of Maryland, 1969.

19. McLain, Howard A., "Potential Metal-Water Reaction in Light-Water-Cooled Power Reactors," ORNL NSIC-23, pp 4-17, August 1968.

20. Cottrell, William B., ORNL Nuclear Safety Research and Development Program Bimonthly Report for January-February 1971, ORNL-TM-3342, p 46, May 1971.

21. IN-1325, Simulated Design Basis Accident Tests of the Carolinas Virginia Tube Reactor - Preliminary Results, J.A. Norberg, et al., October 1969.

22. BNWL-1244, Removal of Iodine and Particles from Containment Atmospheres by Sprays - CSE Interim Report, R. K. Hilliard, et al., February 1970.

23. BNWL-754, Nuclear Safety Quarterly Report - July, August, September, and October 1967; June 1968.

24. BNWL-926, Nuclear Safety Quarterly Report - August, September, and October 1968; December 1968.

25. BNWL-1457, Natural Transport Effects in Fission Product Behavior in the Containment Systems Experiment, R. K. Hilliard and L. F. Coleman, December 1970.

26. Loeb, L. B., "Kinetic Theory of Gases," 3rd Edition, Dover Publications, 1961.

27. Bird, Stewart, and Lightfoot, "Transport Phenomena," John Wiley and Sons, Inc., 1960.

28. Hirchfielder, J. O., Curtiss, C. F., and Bird, R. B., "Molecular Theory of Gases and Liquids," Wiley, New York, 1954.

29. American Institute of Physics Handbook, 3rd edition.

30. Krieth, F., "Principles of Heat Transfer."

31. GE Nuclear Energy, “Mark I Containment Program, Quarter Scale Plant Unique Tests,” NEDO-21944, June 1979.

32. GE Nuclear Energy, “Mark I Containment Program – Full Scale Test Program, Final Report,” NEDO-24539, August 1979.

33. GE Nuclear Energy, “SHEX-04V User’s Manual,” NEDE-30911-1, June 1994.

34. GE-NE-A13-00402-04-R1, “Extended Power Uprate Evaluation Task Report For Edwin I Hatch Plant Units 1 and 2, Containment Evaluations,” September 1998.

35. GE Nuclear Energy, “Safety Review for Edwin I. Hatch Nuclear Power Plant Units 1 and 2 Updated SRV Performance Requirements,” NEDC 32041P, Revision 2, Class III (Proprietary), April 1996.

36. GE Nuclear Energy, “Edwin I. Hatch Nuclear Plant Units 1 and 2 SAFER/GESTR-LOCA Loss of Coolant Analysis,” NEDC-32720P, Class III, (Proprietary), March 1997.

37. Plant Unique Analysis Report, E. I. Hatch Nuclear Plant Unit 1, Revision 2, December 1989, Docket 50-321.

38. Plant Unique Analysis Report, E. I. Hatch Nuclear Plant Unit 2, Revision 2, December 1982, Docket 50-366.

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

40. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” GE-NE-0000-0003-0634-01, Revision 1, GE Nuclear Energy, July 2003.

41. RE 03-254, Reactor Operating Pressure Increase From 1050 psia to 1060 psia, Engineering Evaluations.

42. GE NEDE-22224, “Low-Low Set Relief Set Logic System and Lower MSIV Water Level Trip for Edwin I. Hatch Nuclear Power Plant Units 1 and 2,” December 1982.

43. R. S. Bunker, “E. I. Hatch Nuclear Power Plant Extended Drywell Temperature Analysis,” NSEO-52-0583, June 1983.

44. GE-NE-0000-0012-4850-R0, “Hatch Small Steam Line Break for Equipment Qualification – No HPCI,” February 2003.

45. 10 CFR Part 21 Safety Communication, SC02-22, “Potential Non-Conservatism in Small Steam Line Break Analysis Assumptions for Mark I Containment Equipment Qualification,” December 19, 2002.

46. GEH 0000-0126-6532-R-1, Revision 1, "Ultimate Heat Sink Temperature Increase to 97ºF Impact on DBA-LOCA Analysis and DW Equipment Qualification Analysis," June 2011.

47. GEH Report 001N5657. 1, Rev. 0, "GNF2 Fuel Design Cycle-Independent Analyses for Edwin I. Hatch Nuclear Plant Units 1 and 2," January 2015.

TABLE 6.2-1

PRIMARY CONTAINMENT SYSTEM DESIGN PARAMETERS

General Information	Unit 1	Unit 2
Design Pressure		
Internal - drywell	56.0 psig	56.0 psig
- suppression chamber	56.0 psig	56.0 psig
External - drywell	2.0 psig	2.0 psig
- suppression chamber	2.0 psig	2.0 psig
Design Temperature		
Drywell	281°F	340°F
Suppression chamber	281°F	340°F
Free Volume		
Drywell (including vent system)	Unit 1: 146,010 ft^3	Unit 2: 146,266 ft^3
Suppression chamber		
- approximate minimum	Unit 1: 112,900 ft^3	Unit 2: 109,800 ft^3
- approximate maximum	Unit 1: 115,900 ft^3	Unit 2: 112,800 ft^3
Leakage Rate	1.2% free vol/day	1.2% free vol/day
Downcomer Submergence	4 ft 0 in.	4 ft 4 in.
Overall Vent Resistance Loss Factor	5.51	5.51
No. of Vents	8	8
Normal Vent Diameter (ID)	5 ft 11 in.	6 ft 3 in.
Total Vent Area	220 ft^2	245 ft^2
No. of Downcomers	80	80
Nominal Downcomer Diameter	2.0 ft	2.0 ft

Note: Values are based on the input from OPL-4A for reactor operating pressure increase to 1060 psia.

TABLE 6.2-2 (SHEET 1 OF 3)

TABULATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE[1]

System Name	Pipe Service Description	Isolation Valve Size (in.)	Line Size[2] (in.)	Line Quantity[3]	Remarks
Nuclear boiler	Main steam to main turbine	24	24	4	Design basis MSIV leakage has been explicitly considered, separate from the bypass leakage, in the design basis accident radiological consequences analyses.
	Main steam drainage	3	3	1	
	Reactor feedwater supply	18	18	2	Leakage through these lines must flow through three 18-in. check valves in series per line before release to the turbine building.
Core spray	Pump condensate supply for test	14	14	1	Note 4.
HPCI	Pump condensate suction	14	14	1	Note 4.
	Pump flow test line	10	10	1	Leakage must pass through a normally closed MOV that directs flow via the test line to the CST.
	HPCI steam line condensate to main condenser	10	1	1	
RCIC	Pump condensate suction	6	6	1	Note 4.
	Pump flow test line	4	10	1	Leakage must pass through a normally closed MOV and join the flow from the HPCI test line to the CST.
	RCIC steam line condensate to main condenser	4	1	1	

TABLE 6.2-2 (SHEET 2 OF 3)

System Name	Pipe Service Description	Isolation Valve Size (in.)	Line Size[2] (in.)	Line Quantity[3]	Remarks
Radwaste	Equipment drain sump	3	3	1	Note 5.
	Floor drain sump discharge	3	3	1	
	Chemical drain sump discharge	1 1/2	1 1/2	1	Note 5.
RWC	Drainage to main condenser	6	4	1	Note 6.
	Drainage to radwaste	-	4	1	Note 6.
Torus drainage and purification	Effluent to main condenser	3	3	1	Note 7.
	Influent from containment	3	3	1	Note 4.
RBCCW	Influent to containment	4	-	1	Closed-loop system inside primary containment.
	Return from containment	4	-	-	Closed-loop system inside primary containment.
Containment N_2 purge	Gas supply to containment and drywell pneumatic system	1 2 6	1 2 6	1	Note 8. Note 8. Notes 8 and 9.
Reactor building/ drywell chilled water	Influent to containment	6	-	1	Closed-loop system inside primary containment.
	Effluent from containment	-	-	-	

NOTES

1. The estimated total bypass leakage from the lines listed in table 6.2-2 does not exceed 2.0% per day of the design containment leakage. This value was chosen to ensure the resultant offsite radiological consequences of the design basis LOCA do not exceed the limits specified in 10 CFR 50.67.

2. Pipe size at the secondary containment wall.

TABLE 6.2-2 (SHEET 3 OF 3)

3. Total number of lines that pass through the secondary containment.

4. The lines for HPCI and RCIC system pump suction piping, the CS system, CST suction piping, and the torus drainage and purification influent piping from the CST are continuously filled with water from the CST to the isolation valve, and with suppression pool water to the pump side of the isolation valve. Therefore, no leakage to the environment is postulated to occur.

5. The containment drainage sumps are located in the base of the drywell and are flooded with coolant following the postulated LOCA. This flooding creates a water seal inside the containment up to the closed isolation valves. These valves are leak tested in accordance with 10 CFR 50, Appendix J, and their leakage rates form a part of the total bypass leakage fraction.

6. The RWC system is isolated from the nuclear process through the closure of two 6-in. isolation valves in series on the influent line, and through the closure of the 18-in. feedwater system air-operated check valves at the system effluent, as well as a 4-in. RWC system effluent check valve. The leakage estimated is the combined leakrate through the 6-in. isolation valves and the 18-in. feedwater check valves. Directing drainage to either the radwaste system or the main condenser does not affect the estimate of bypass, leakage since both 4-in. lines receive from the RWC system loop connecting the 6-in. and 18-in. isolation valves. See drawing nos. H-26000, -26001, -26036, -26037, and -26189.

7. The effluent torus drainage and purification system line, by virtue of its connection to the invert of the suppression chamber, is always provided with a water seal from the containment.

8. The containment gas purge supply piping is Seismic Category I piping, which is pressurized to a pressure of ~ 120 psig by the Seismic Category I nitrogen supply system, thus precluding the possibility of leakage to the environment from the containment through these lines.

9. The drywell inerting piping is sealed from the containment by spectacle flanges and is not used during plant operation.

TABLE 6.2-3 (SHEET 1 OF 2)

ESF FLOW INPUT PARAMETERS FOR LOCA ANALYSIS (HNP-1 AND HNP-2)

System	Full Capacity	Value Used for Containment Analysis[a]
HPCI		
No. of lines	1	None
No. of pumps	1	None
Flowrate (gal/min)	4250	None
LPCI		
No. of lines	2	1
No. of pumps	4	1
Flowrate/pump (gal/min)	7700	7700
CS		
No. of lines	2	1
No. of pumps	2	1
Flowrate/loop (gal/min)	4625	4250
ADS		
No. of lines	7	None
No. of valves	7	None
Total capacity/valve (lb/h)	870,000	None
Supplemental Systems		
Containment Spray[b]		
No. of lines	1	None
No. of pumps	2	None
No. of headers	1	None
Flowrate (gal/min)	11,530	None
RHR Heat Exchangers		
Type	AEU	AEU
No.	2	1
Heat transfer area (ft^2)	4570	4570
Overall heat transfer coefficient assumed in analysis (Btu/s - °F)	NA	Temperature Dependent[c]
Flowrates		
- RHR (gal/min)	7700	7700
Source of cooling water	River	River
Flow begins (s)	600	600

TABLE 6.2-3 (SHEET 2 OF 2)

---

a. Worst case.
b. Heat removal capability of the containment spray system is not used in the containment analysis.
c. Reference GEH 0000-0126-6532-R1, Revision 1, "Ultimate Heat Sink Temperature Increase to 97ºF Impact on DBA-LOCA Analysis and DW Equipment Qualification Analysis," June 2011.

TABLE 6.2-4

PRIMARY SYSTEM ENERGY DISTRIBUTION WHEN RECIRCULATION LINE BREAK ACCIDENT OCCURS (HNP-1 AND HNP-2)

Fluid Energy	Energy (10^6 Btu)
Steam	17.8
Liquid	244.9
Sensible Energy	
RPV	81.1
RPV internals (less core) plus primary system piping	67.8
Fuel	20.9

NOTE:

Both fluid and metal energies are based upon a datum temperature of 32°F. Uranium (U_2) energy is based upon a datum temperature of 285°F.

TABLE 6.2-6 (SHEET 1 OF 2)

DBA-LOCA INITIAL CONDITIONS, ASSUMPTIONS, AND CALCULATED PRESSURE RESULTS (HNP-1 AND HNP-2)

Initial Conditions [100.5% of RTP (2804 MWt)]	HNP-1	HNP-2
Reactor Coolant System		
Reactor power level	2818 MWt	2818 MWt
Mass of RPV liquid (less feedwater)	496,000 lb	496,000 lb
Coolant temperature	551.7°F	551.7°F
Mass of RPV steam	18,000 lb	18,000 lb
RPV dome pressure	1063 psia	1073 psia[(e)]
Primary Containment		
Pressure	1.75 psig	1.75 psig
Temperature (drywell air)	150°F	150°F
Relative humidity		
- Drywell	20%	20%
- Suppression chamber	100%	100%
RHRSW	97°F	97°F
Suppression pool water temperature	100°F	100°F (85°F)[(a)]
Stored Water		
Suppression pool		
- approximate minimum	85,110 ft^3	86,420 ft^3
- approximate maximum	88,190 ft^3	89,670 ft^3
CST	66,845 ft^3	66,850 ft^3
Effective Accident Break Area	3.987 ft^2[(b)] (4.378 ft^2)[(c)] (3.987 ft^2)[(d)]	4.163 ft^2[(e)] (3.987 ft^2)[(b)] (4.378 ft^2)[(c)] (3.987 ft^2)[(d)]
Break Area/Vent Area	0.0194[(c)] 0.0173[(b)(d)]	0.0165[(b)] (0.0202[(c)]) (0.0165[(d)])
NSSS		
- Volume of water in RPV	8963 ft^3	9118 ft^3
- Volume of steam in RPV	6881 ft^3	6258 ft^3
- Volume of water in recirc loops	1002 ft^3	845 ft^3
- Total primary system volume	16,846 ft^3	16,221 ft^3

TABLE 6.2-6 (SHEET 2 OF 2)

	HNP-1	HNP-2
Break Sizes (Original LOCA Analysis)		
	Assumed Pipe Break Area	
	4.378 ft^2	0.1 ft^2
Peak Pressure	57.51 psig	25 psig
Peak Temperature	304°F	270°F
Time of Peak Pressure	9 s	10^3 s
Energy Released to Containment at Peak Pressure	224.29 x 10^6 Btu	261.40 x 10^6 Btu
DBA-LOCA Calculated Results		
Calculated Peak Pressure During Blowdown (No Purge) - Drywell	50.78[(b)] (59.0 psig)[(c)]	47.22[(b)] (46.7 psig)[(c)]
Calculated Peak Suppression Pool Temperature During Blowdown	210.2°F[(d)]	207.5°F[(d)]

a. The acceptability of the initial suppression pool temperature of 100°F and its negligible impact on the containment analyses are contained in EAS-19-0388.[(2)]
b. Value is based upon the analysis for an RTP of 2804 MWt and reactor operating pressure of 1060 psia.
c. Value is based upon Mark I Long-Term Containment Program modifications and operation in the EOD.
d. Value is based on LOCA analysis (direct pool cooling).
e. Value is based upon the analysis with GNF2 fuel for an RTP of 2804 MWt and normal reactor operating pressure of 1060 psia.

TABLE 6.2-7

DRYWELL TEMPERATURE ENVELOPE
FOR
BREAK SIZES OF 0.01 ft^2, 0.1 ft^2, AND 0.5 ft^2
(HNP-1 AND HNP-2)

Time Following Accident	Drywell Temperature (°F)[1]
0 to 1800 s	329
1800 to 2500 s (0.029 days)	329 to 320
0.029 to 0.62 days	320 to 200 (linearly)
0.62 to 1.0 day	200 to 189

1. Small steam line break drywell temperature profiles for 0.01 ft^2, 0.1 ft^2, and 0.5 ft^2 size break run only up to a maximum of 1 day in references 44 and 46.

TABLE 6.2-8

REACTOR ENERGY DISTRIBUTION FOLLOWING RECIRCULATION LINE BREAK (HNP-1 AND HNP-2)

HNP-1

Blowdown Table for Recirculation Line Break (Original LOCA Analysis)

Time (s)	Liquid Flow (lb/s)	Liquid Enthalpy (Btu/lb)	Steam Flow (lb/s)	Steam Enthalpy (Btu/lb)
0	34,470	550.5	0	1189
10.70	34,680	552.8	0	1189
10.71	14,660	551.8	5900	1189
14.2	8300	498.7	4800	1200
16.7	5200	457.3	3800	1204
20.6	2200	394.4	2400	1203

HNP-2

Blowdown Table for Recirculation Line Break (Original LOCA Analysis)

Time (s)	Liquid Flow (lb/s)	Liquid Enthalpy (Btu/lb)	Steam Flow (lb/s)	Steam Enthalpy (Btu/lb)
0	34980	550.7	0	1190.2
11.08	34310	543.2	0	1192.2
11.09	17660	543.2	4877	1192.2
14.2	11610	500.3	4320	1200.8
16.7	7905	463.1	3625	1204.7
20.7	3748	400.6	2328	1204.4
25.2	1479	333.5	1294	1195.5
30.0	416	269.8	588	1180.2
30.7	0	252.8	0	1175.2

NOTE: Passive heat sinks are not used at HNP-2.

TABLE 6.2-9

SECONDARY CONTAINMENT POST-LOCA HEAT LOADS AND CORNER ROOM COOLER CAPACITIES

Room	Heat Load Due to Lighting and ECCS Equipment (Btu/h)	Cooler Capacity[a] (Btu/h)
Reactor building above el 130 ft	6640[b]	None
Torus chamber room	3501[b]	None
CRD room	93,500	110,000
RCIC room	50,000	75,000
NE RHR/CS room	750,200	900,000
SE RHR/CS room	750,200	975,000
HPCI room	Negligible	110,000[c]

a. Cooler capacity based upon service water inlet temperature of 95°F.
b. Lighting only.
c. No credit is taken for this cooler.

TABLE 6.2-10 (SHEET 1 OF 8)

SECONDARY CONTAINMENT PRESSURE AND TEMPERATURE RESPONSE POST-LOCA[a]

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
0	1	90.000	14.696
	2	80.000	14.696
	3	104.000	14.696
	4	80.000	14.696
	5	80.000	14.696
	6	80.000	14.696
	7	80.000	14.696
2	1	89.990	14.698
	2	80.002	14.698
	3	103.624	14.697
	4	80.441	14.699
	5	82.121	14.697
	6	82.118	14.697
	7	80.001	14.698
4	1	89.984	14.700
	2	80.003	14.700
	3	103.261	14.698
	4	80.811	14.700
	5	84.136	14.698
	6	84.131	14.698
	7	80.003	14.700
6	1	89.981	14.701
	2	80.005	14.701
	3	103.913	14.700
	4	81.199	14.702
	5	86.050	14.700
	6	86.043	14.700
	7	80.005	14.701

TABLE 6.2-10 (SHEET 2 OF 8)

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
8	1	89.980	14.703
	2	80.006	14.703
	3	102.579	14.702
	4	81.576	14.704
	5	87.867	14.702
	6	87.857	14.702
	7	80.007	14.703
10	1	89.982	14.704
	2	80.007	14.704
	3	102.260	14.703
	4	81.943	14.705
	5	89.592	14.703
	6	89.580	14.703
	7	80.009	14.704
12	1	89.986	14.706
	2	80.009	14.706
	3	101.970	14.705
	4	82.311	14.707
	5	91.228	14.705
	6	91.215	14.705
	7	80.012	14.706
14	1	89.922	14.707
	2	80.010	14.707
	3	101.692	14.706
	4	82.667	14.708
	5	92.781	14.706
	6	92.766	14.706
	7	80.015	14.707
16	1	90.001	14.709
	2	80.012	14.709
	3	101.426	14.707
	4	83.014	14.709
	5	94.254	14.707
	6	94.237	14.707
	7	80.018	14.709

TABLE 6.2-10 (SHEET 3 OF 8)

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
18	1	90.010	14.710
	2	80.013	14.710
	3	101.186	14.709
	4	83.360	14.711
	5	95.650	14.711
	6	95.631	14.711
	7	80.021	14.710
50	1	90.392	14.703
	2	80.024	14.703
	3	97.982	14.705
	4	87.756	14.705
	5	110.009	14.705
	6	109.972	14.705
	7	80.087	14.703
55	1	90.475	14.702
	2	80.025	14.702
	3	97.665	14.703
	4	88.274	14.703
	5	111.306	14.703
	6	111.268	14.703
	7	80.099	14.702
60	1	90.563	14.701
	2	80.027	14.701
	3	97.386	14.702
	4	88.757	14.702
	5	112.435	14.702
	6	112.396	14.702
	7	80.113	14.701
65	1	90.654	14.700
	2	80.029	14.699
	3	97.141	14.700
	4	89.204	14.700
	5	113.419	14.700
	6	113.378	14.700
	7	80.126	14.699

TABLE 6.2-10 (SHEET 4 OF 8)

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
70	1	90.746	14.698
	2	80.031	14.698
	3	96.927	14.699
	4	89.627	14.699
	5	114.277	14.699
	6	114.235	14.699
	7	80.140	14.698
75	1	90.842	14.696
	2	80.032	14.696
	3	96.740	14.698
	4	90.020	14.698
	5	115.025	14.698
	6	114.982	14.698
	7	80.154	14.696
120	1	91.772	14.685
	2	80.050	14.686
	3	95.944	14.687
	4	92.651	14.687
	5	118.741	14.687
	6	118.693	14.687
	7	80.289	14.686
130	1	91.987	14.683
	2	80.054	14.683
	3	95.912	14.683
	4	93.078	14.684
	5	119.151	14.684
	6	119.102	14.684
	7	80.320	14.683
140	1	92.203	14.691
	2	80.059	14.691
	3	95.913	14.692
	4	93.466	14.692
	5	119.487	14.692
	6	119.437	14.692
	7	80.352	14.691

TABLE 6.2-10 (SHEET 5 OF 8)

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
150	1	92.419	14.679
	2	80.063	14.679
	3	95.941	14.680
	4	93.823	14.680
	5	119.766	14.680
	6	119.715	14.680
	7	80.384	14.679
160	1	92.636	14.676
	2	80.067	14.676
	3	95.991	14.678
	4	94.151	14.678
	5	120.004	14.678
	6	119.951	14.678
	7	80.416	14.676
170	1	92.852	14.674
	2	80.072	14.674
	3	96.058	14.675
	4	94.457	14.675
	5	120.210	14.675
	6	120.157	14.675
	7	80.448	14.674
280	1	95.189	14.653
	2	80.127	14.653
	3	97.327	14.654
	4	96.994	14.654
	5	121.727	14.654
	6	121.659	14.654
	7	80.813	14.653
300	1	95.592	14.649
	2	80.137	14.649
	3	97.605	14.650
	4	97.385	14.650
	5	122.222	14.648
	6	122.043	14.648
	7	80.879	14.649

TABLE 6.2-10 (SHEET 6 OF 8)

Time (s)	Volume No.[(b)]	Temperature (°F)	Pressure (psia)
320	1	95.974	14.645
	2	80.140	14.645
	3	97.908	14.646
	4	89.164	14.643
	5	123.317	14.641
	6	123.202	14.641
	7	81.003	14.642
340	1	96.359	14.642
	2	80.143	14.642
	3	97.191	14.643
	4	98.524	14.639
	5	123.654	14.637
	6	123.551	14.637
	7	81.066	14.638
360	1	96.742	14.638
	2	80.146	14.638
	3	98.458	14.639
	4	98.524	14.639
	5	123.654	14.637
	6	123.551	14.637
	7	81.066	14.638
380	1	97.124	14.635
	2	80.150	14.635
	3	98.725	14.636
	4	98.871	14.636
	5	123.928	14.634
	6	123.830	14.634
	7	81.130	14.635
500	1	99.353	14.615
	2	80.173	14.615
	3	100.205	14.616
	4	100.802	14.616
	5	135.153	14.614
	6	125.054	14.614
	7	81.517	14.615

TABLE 6.2-10 (SHEET 7 OF 8)

Time (s)	Volume No.[b]	Temperature (°F)	Pressure (psia)
550	1	100.246	14.608
	2	80.185	14.607
	3	100.792	14.609
	4	101.560	14.609
	5	125.606	14.606
	6	125.503	14.606
	7	81.681	14.607
600	1	101.119	14.600
	2	80.198	14.600
	3	101.363	14.601
	4	102.297	14.601
	5	126.046	14.599
	6	125.940	14.599
	7	81.846	14.600
650	1	101.970	14.593
	2	80.211	14.593
	3	101.922	14.594
	4	103.015	14.595
	5	126.476	14.592
	6	126.365	14.592
	7	82.013	14.593
700	1	102.802	14.587
	2	80.225	14.587
	3	102.466	14.588
	4	103.716	14.588
	5	126.895	14.586
	6	126.780	14.586
	7	82.181	14.587
750	1	103.613	14.581
	2	80.240	14.581
	3	102.998	14.582
	4	104.400	14.582
	5	127.304	14.580
	6	127.186	14.580
	7	82.351	14.581

TABLE 6.2-10 (SHEET 8 OF 8)

---

a. The LOCA occurs at time = 0.

b. Volumes are as follows:

   1. Main reactor building volume above el 130 ft.
   2. Torus chamber room.
   3. CRD corner room.
   4. RCIC corner room.
   5. Northeast RHR corner room.
   6. Southeast RHR corner room.
   7. HPCI room.

TABLE 6.2-11

PARAMETER VALUES FOR CALCULATING HYDROGEN AND OXYGEN CONCENTRATIONS IN CONTAINMENT

Fraction of fission products radiation energy absorbed by coolant[a]	Beta: From fission products in fuel rods = 0 From fission products intimately mixed with coolant = 1.0 Gamma: From fission products in rods, coolant in core region = 0.1[b] From fission products intimately mixed with coolant, all coolant = 1.0
G (H_2)[a]	0.5 molecules/100 ev
G (O_2)[a]	0.25 molecules/100 ev
Extent of metal-water reaction (percentage of fuel cladding that reacts with water)	5
Aluminum corrosion rate for aluminum exposed to alkaline solutions. (This value should be adjusted upward for higher temperatures early in accident sequence.)	200 mils/year
Fission product distribution model	50% of halogens and 1% of solids present in core are intimately mixed with coolant water. All noble gases are released to containment
Hydrogen concentration limit. This limit should not be exceeded if more than 5-v/o oxygen is present.	4 v/o
Oxygen concentration limit. This limit should not be exceeded if more than 4-v/o hydrogen is present.	5 v/o

a. For water, borated water, and borated alkaline solutions; for other solutions, data should be presented.
b. This fraction is conservative; further analysis may show the fraction should be revised.

TABLE 6.2-14 (SHEET 1 OF 2)

SGTS COMPONENT DESCRIPTION

Component	Description
Filter Trains	
Number	2
Size	100% capacity trains
Type	Multiple filters for removal of particulates, elemental iodine, and organic iodine from air
Capacity (sf^3/min)	4000 each
Charcoal Adsorber (Each Train)	
Number	1 set
Type	Deep bed
Capacity (sf^3/min)	4000 maximum
Media	Activated charcoal
Efficiency percent at 30°C/70% relative humidity(laboratory tested)	97.5 of methyl iodide
Charcoal volume ft^3	37
Depth of bed (in.)	4 minimum
Face velocity (ft/min)	50
Residence time (s)	0.46 minimum
Ignition temperature (minimum °F)	626
Iodine desorption temperature (minimum °F)	356
Design iodine loading (30-day accident duration)	2.5 maximum iodine per gram of activated charcoal
Pressure drop (clean) (in. wg)	3.20
Charcoal weight (lb) (actual/required)	1260/1130
Particle size distribution (mesh)	8 x 16
HEPA Filters (Each Train)	
Number	2 banks
Type	High efficiency, dry
Capacity (sf^3/min)	4000 maximum each bank
Media	Glass fiber (waterproof and fire retardant)
Efficiency (%)	99.95 with 0.3 mm DOP smoke
Pressure drop (clean) (in. wg)	1.0

TABLE 6.2-14 (SHEET 2 OF 2)

Component	Description
Prefilters (Each Train)	
Number	1 bank
Type	Dry
Capacity (sf^3/min)	4000 maximum
Media	Glass fiber
Efficiency (%)	40 average dust spot
Pressure drop (clean) (in. wg)	0.31
Heaters (Each Train)	
Number	1
Type	Electric
Rating (kW)	15
SGTS Fans (Each Train)	
Number	1
Size	100% capacity units
Type	Centrifugal
Capacity (sf^3/min)	4000 maximum
Drive	Vee-belt

TABLE 6.2-15 (SHEET 1 OF 2)

SGTS FAILURE ANALYSIS

Component	Malfunction	Comments
SGTS fan	Failure of fan resulting in over-load trip	If operating fan fails, resultant over- load actuates alarm in MCR, automatically starts standby filter fan, and opens standby filter train isolation valves.
SGTS fan	Failure of fan or Vee-belt drive resulting in reduced or no flow as detected by flow switches and alarmed in MCR.	Standby fan is manually started.
Electric heating coil	Failure of heating coil air flow switch constant coil operation.	High temperature alarm occurs, resulting in MCR temperature of 190°F. Heater will trip due to high temperature cutout switch set at 290°F. Redundant filter train is available for manual operation.
	Failure of coil or control resulting in no heat.	The heater is not credited for maintaining the filter efficiency. Heater operation lights indicate heater malfunction.
SGTS filter train	Failure resulting in high pressure differential across filter train	High-pressure differential across filter train automatically actuates alarm in MCR. Defective filter train is manually isolated, and standby train is manually brought into operation.
SGTS filter train	Failure resulting in high-radiation at discharge, as detected by monitor in stack and alarmed in MCR.	Redundant filter train can be manually placed in operation upon high-radiation signal.

TABLE 6.2-15 (SHEET 2 OF 2)

Component	Malfunction	Comments
Charcoal adsorber	High temperature in charcoal bed.	Temperature switches provided in each charcoal adsorber alarm in MCR on rising charcoal temperature. Deluge system is manually activated as needed.
Isolation damper	Failure to close or close completely as shown by lights in MCR.	Redundant damper automatically provides required isolation.
Operational damper	Failure to open or open completely as shown by lights in MCR.	Redundant filter train automatically provides parallel path required.

TABLE 6.2-16

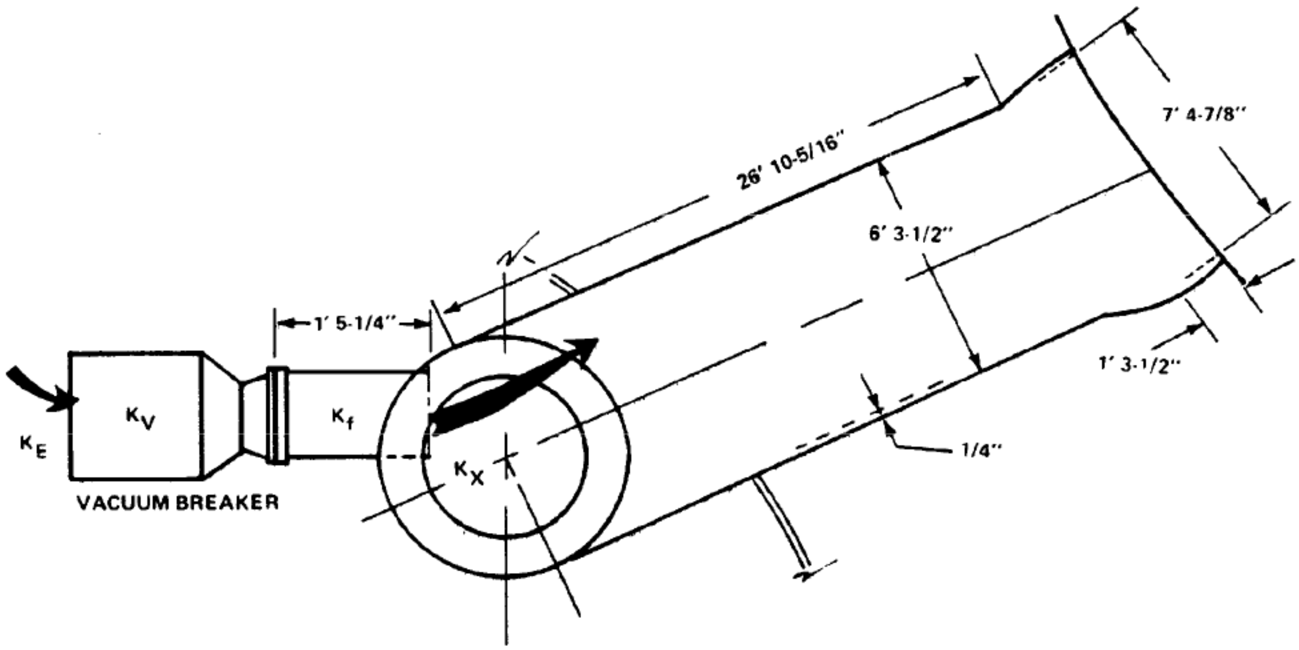
Deleted.

TABLE 6.2-17

Deleted.

TABLE 6.2-18

Deleted.



LEGEND

K_E = ENTRANCE LOSS COEFFICIENT
K_V = VALVE HEAD LOSS COEFFICIENT
K_f = PIPE HEAD LOSS COEFFICIENT
K_X = PIPE EXIT LOSS COEFFICIENT

LOSS COEFFICIENTS

K_E	= 0.78
K_V	= 0.54 (EMPIRICAL)
K_f	= 0.013
K_X	= 1.00
K_{TOTAL}	= 2.333

ACAD 2060201

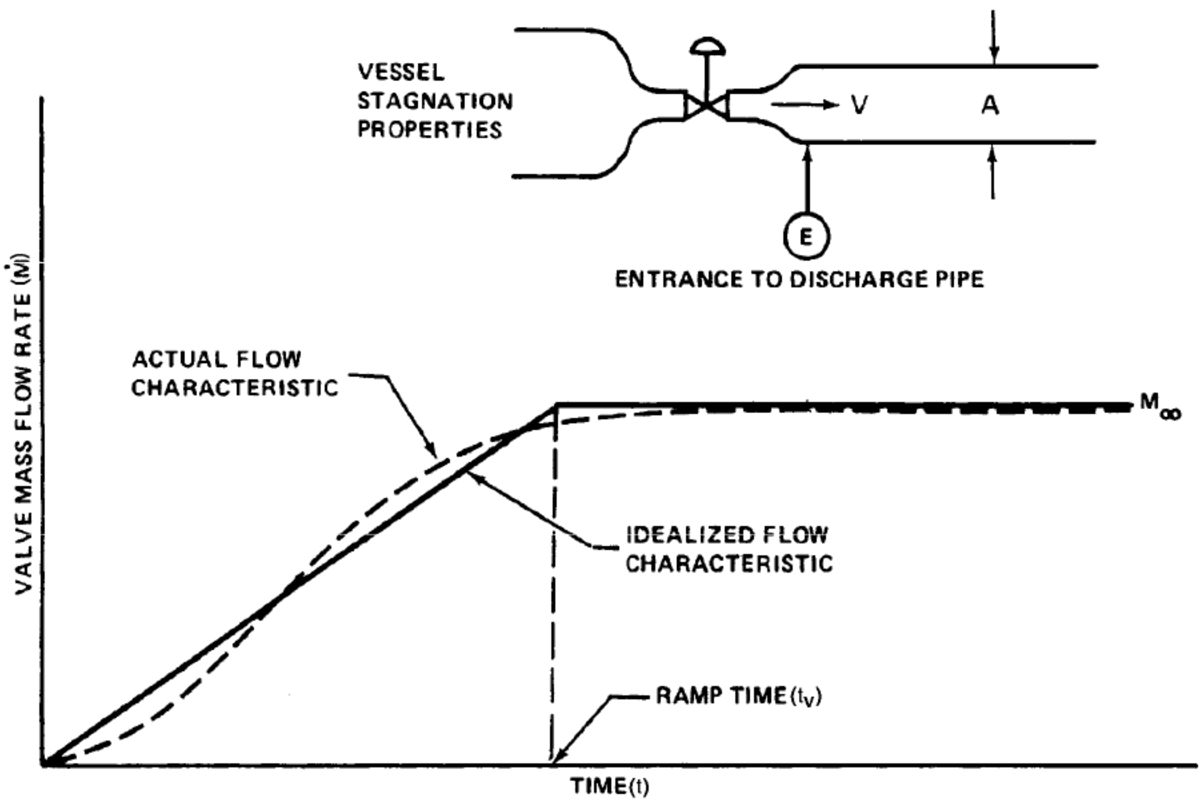
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SUPPRESSION CHAMBER-TO-DRYWELL
VACUUM BREAKER

FIGURE 6.2-1



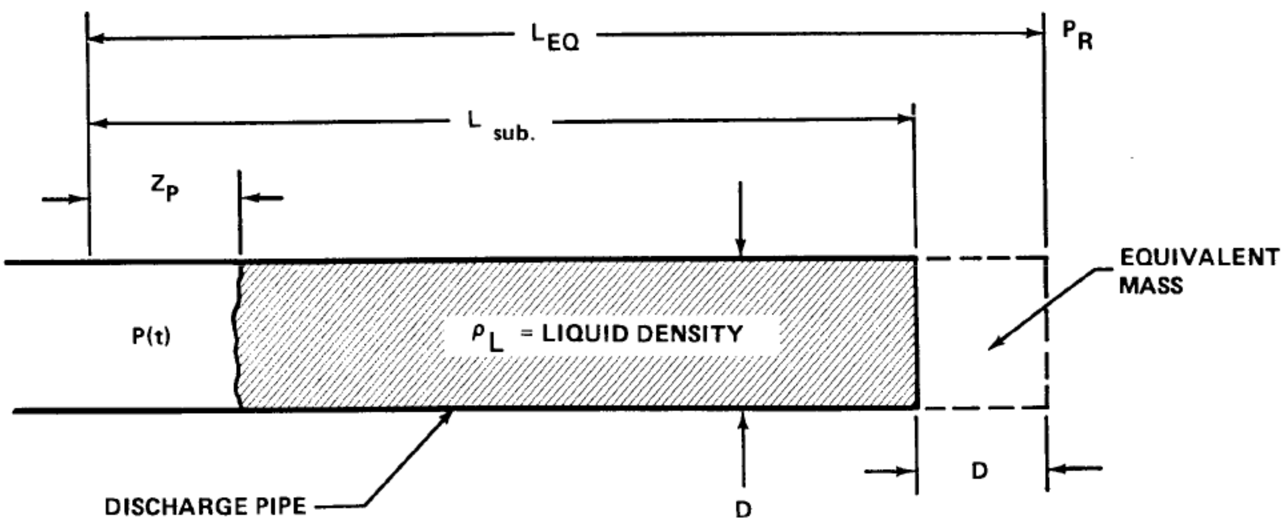
ACAD 2060213

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SRV STEAM FLOW CHARACTERISTICS

FIGURE 6.2-2



LEGEND

L_{EQ} = equivalent length
Z_p = arbitrary length defining wave boundary interface with water slug
P_R = receiver pressure
ρ_L = liquid density
P(t) = pressure applied to water column

ACAD 2060214

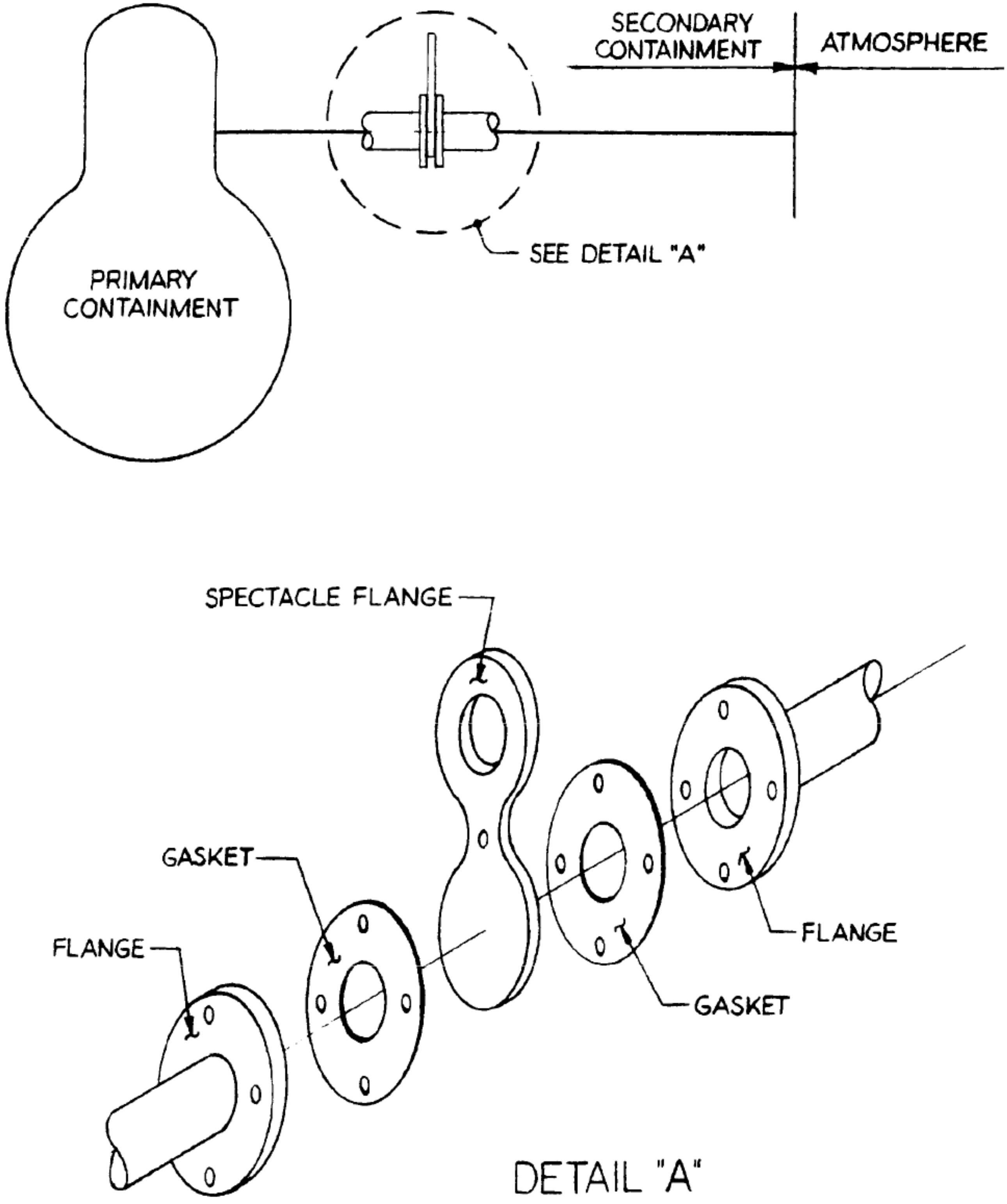
REV 19 7/01

SOUTHERN COMPANY *Energy to Serve Your World*

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SRV DISCHARGE PIPE SUBMERGED END

FIGURE 6.2-3



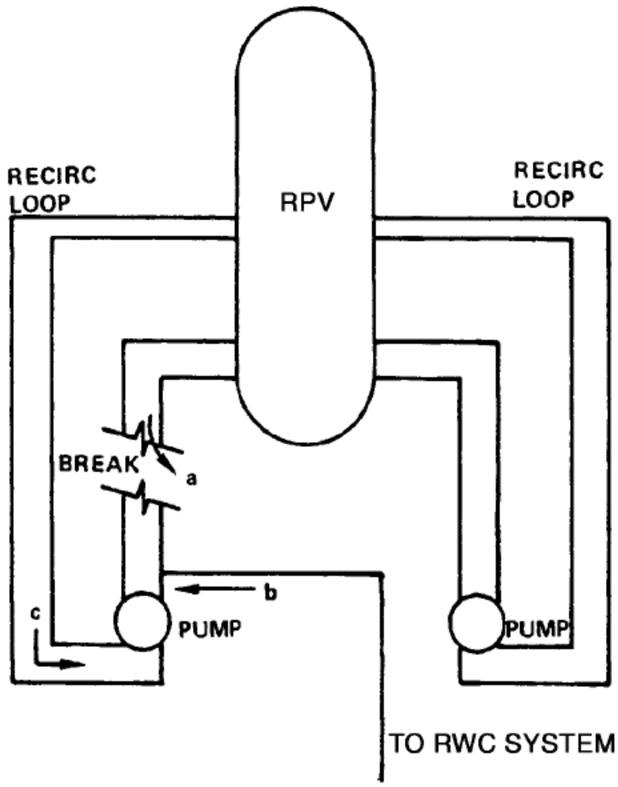
ACAD 2060238

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL SPECTACLE FLANGE ARRANGEMENT

FIGURE 6.2-4



POINT OF CRITICAL FLOW

a = RECIRC LINE
b = CLEANUP LINE
c = 10 JET PUMP NOZZLES FOR EACH FLOW

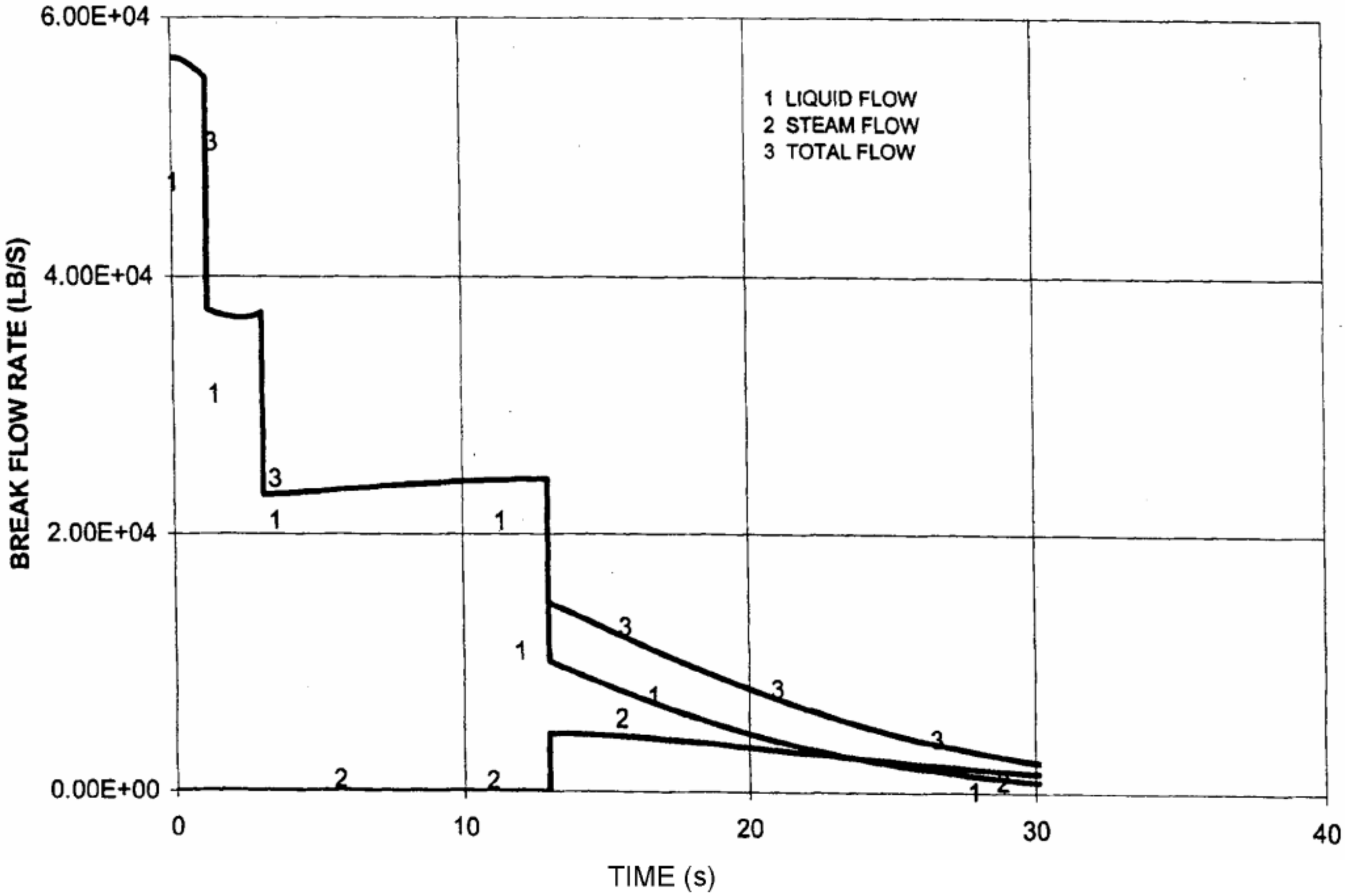
ACAD 2060215

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LOCATION OF RECIRCULATION LINE BREAK

FIGURE 6.2-5



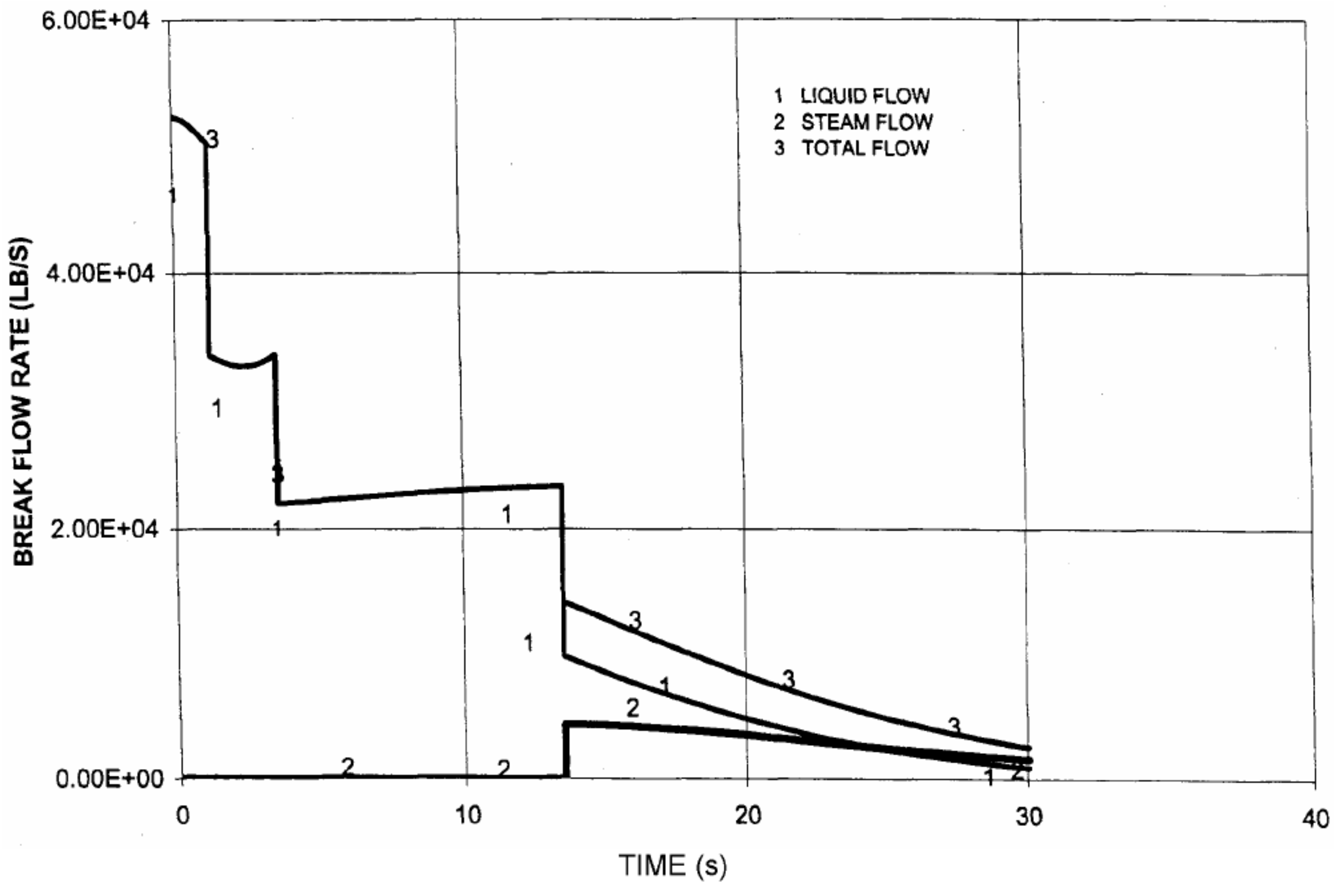
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

RECIRCULATION BREAK
BLOWDOWN FLOWRATES (HNP-1)

FIGURE 6.2-6



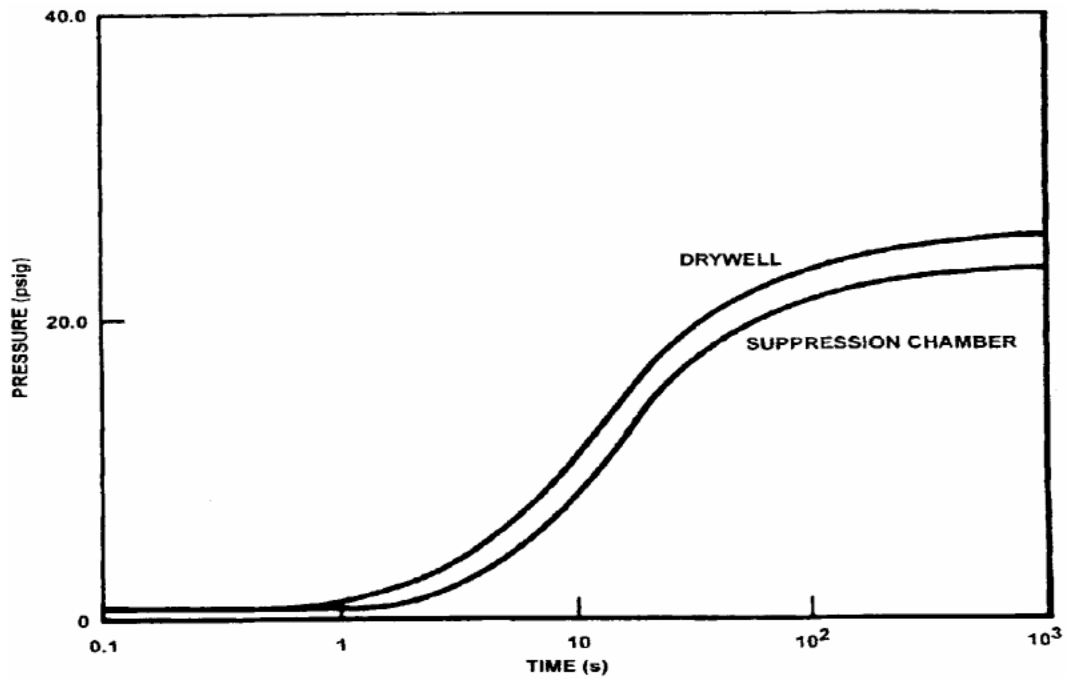
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

RECIRCULATION BREAK
BLOWDOWN FLOWRATES (HNP-2)

FIGURE 6.2-7



ORIGINAL

ACAD 2060223

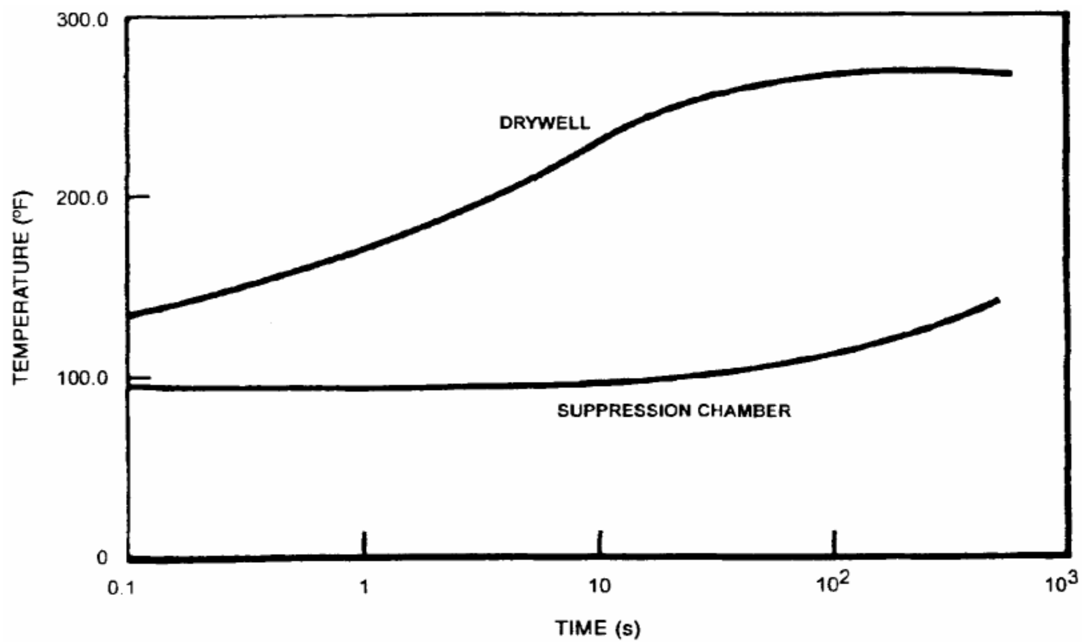
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

0.1-ft^2 LIQUID BREAK-CALCULATED DRYWELL AND SUPPRESSION CHAMBER PRESSURE RESPONSES

FIGURE 6.2-8



ORIGINAL

ACAD 2060224

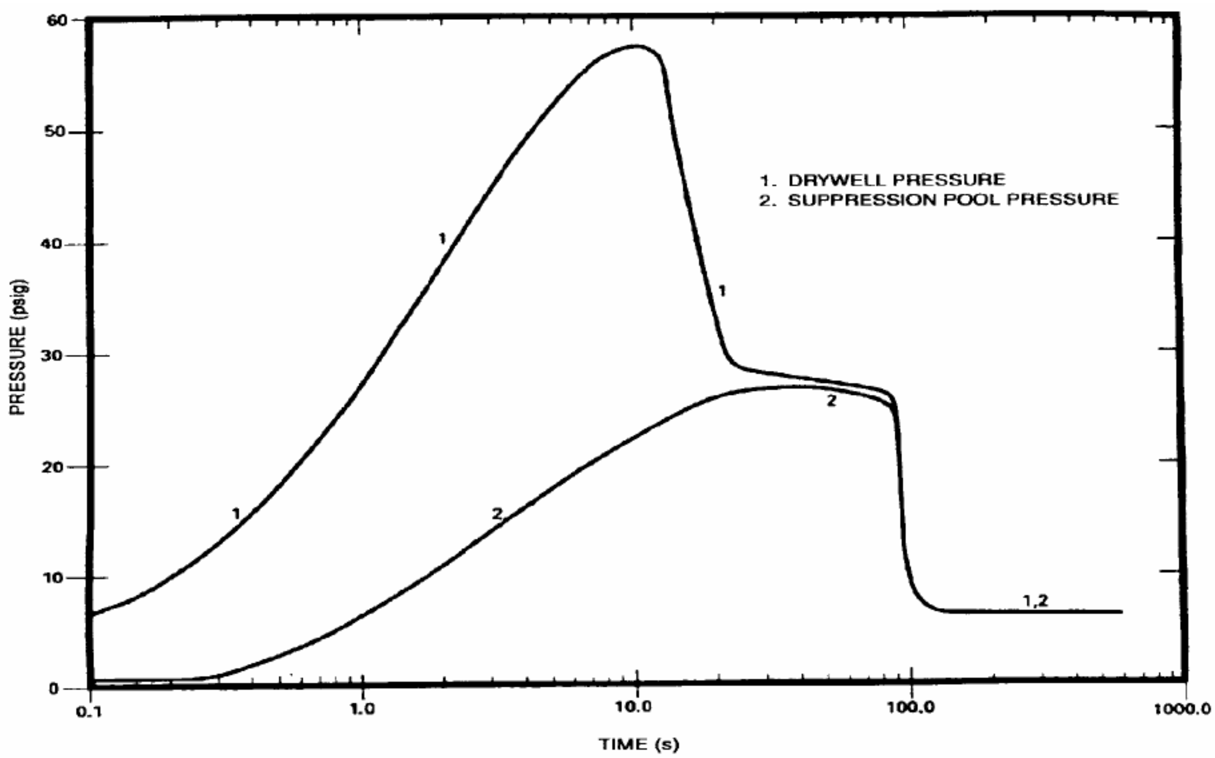
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

0.1-ft^2 LIQUID BREAK-CALCULATED DRYWELL AND SUPPRESSION CHAMBER TEMPERATURE RESPONSES

FIGURE 6.2-9



ORIGINAL

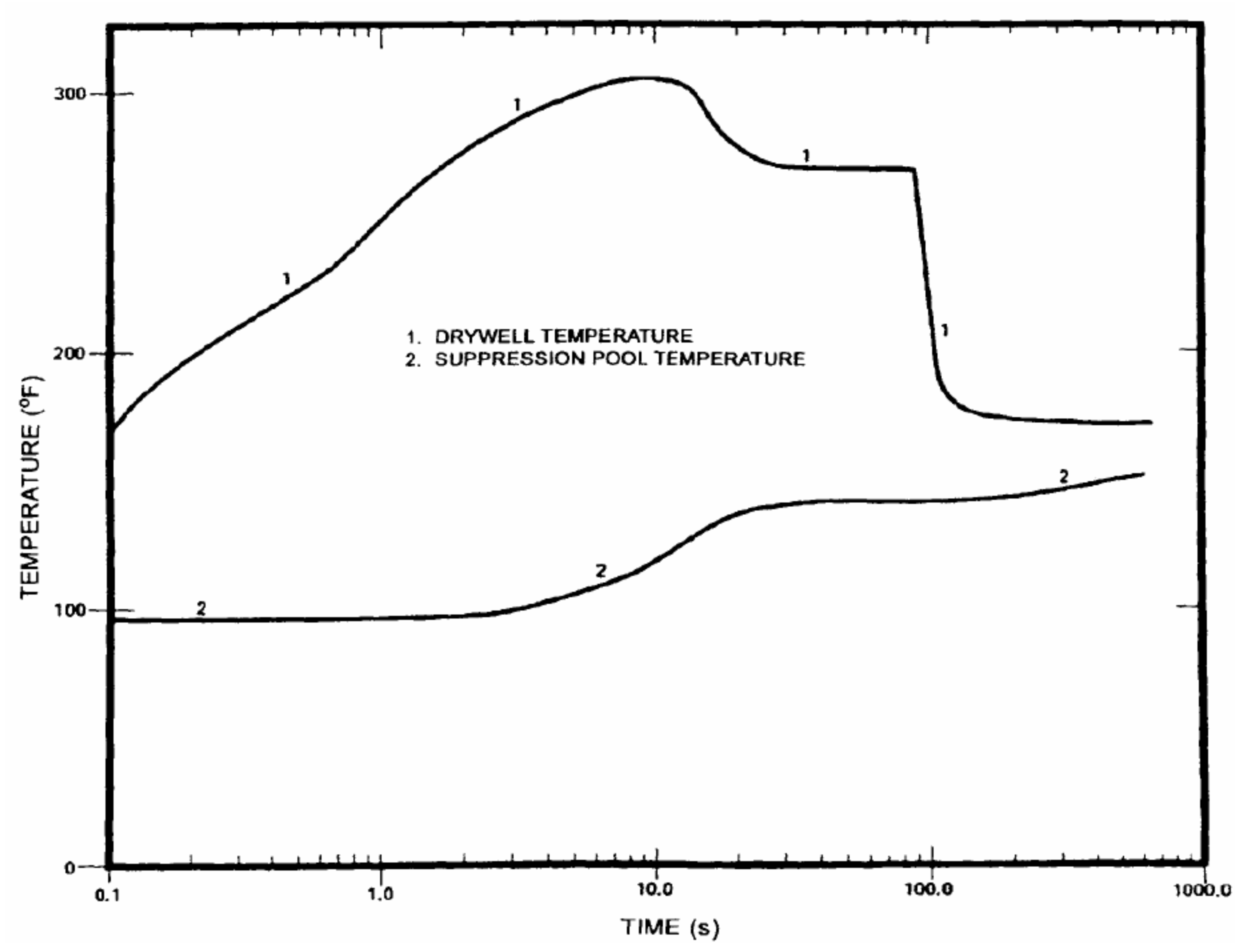
ACAD 2060218

REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

RECIRCULATION LINE BREAK CALCULATED CONTAINMENT PRESSURE RESPONSE

FIGURE 6.2-10



ORIGINAL

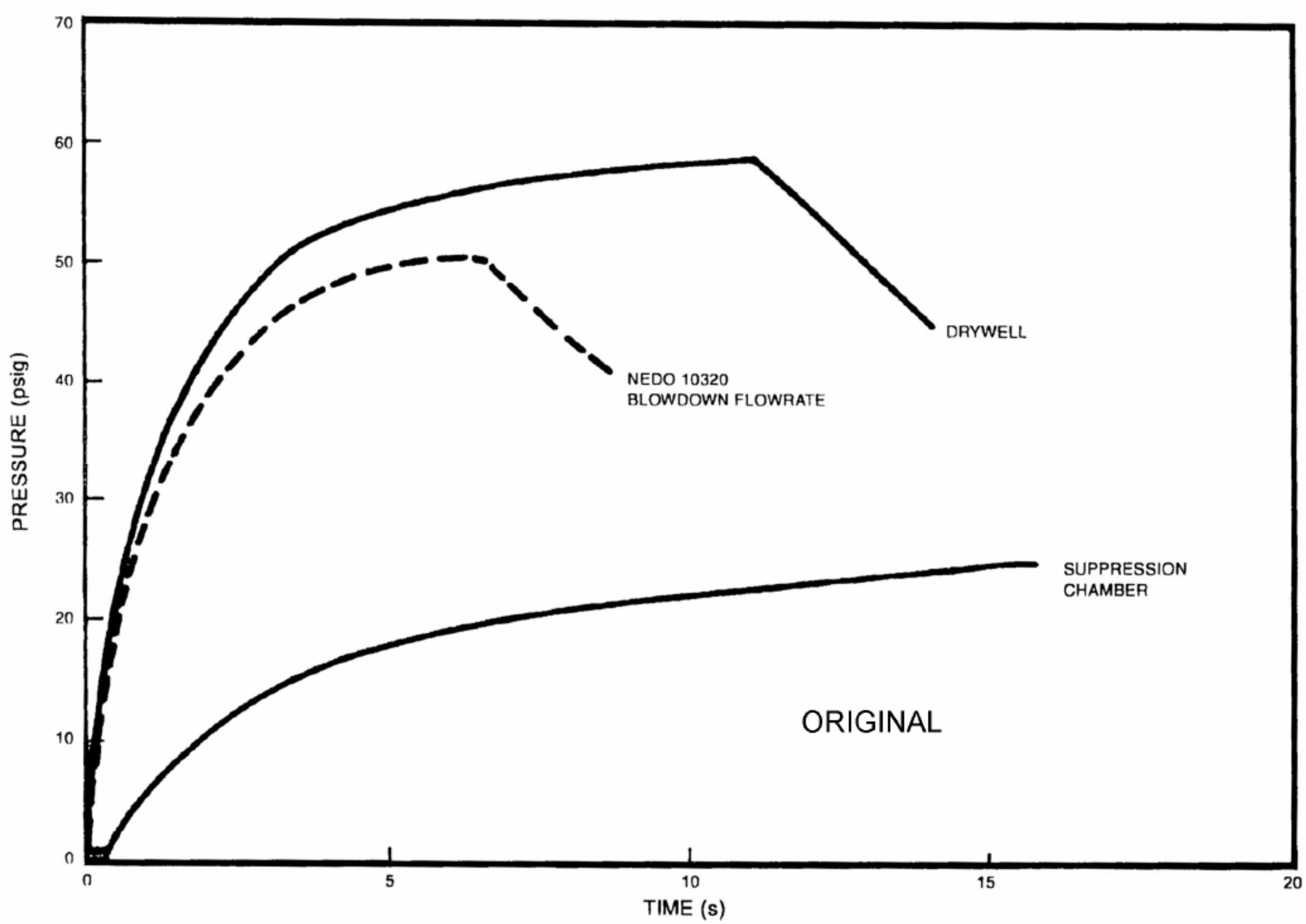
ACAD 2060219

REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

RECIRCULATION LINE BREAK CALCULATED CONTAINMENT TEMPERATURE RESPONSE

FIGURE 6.2-11



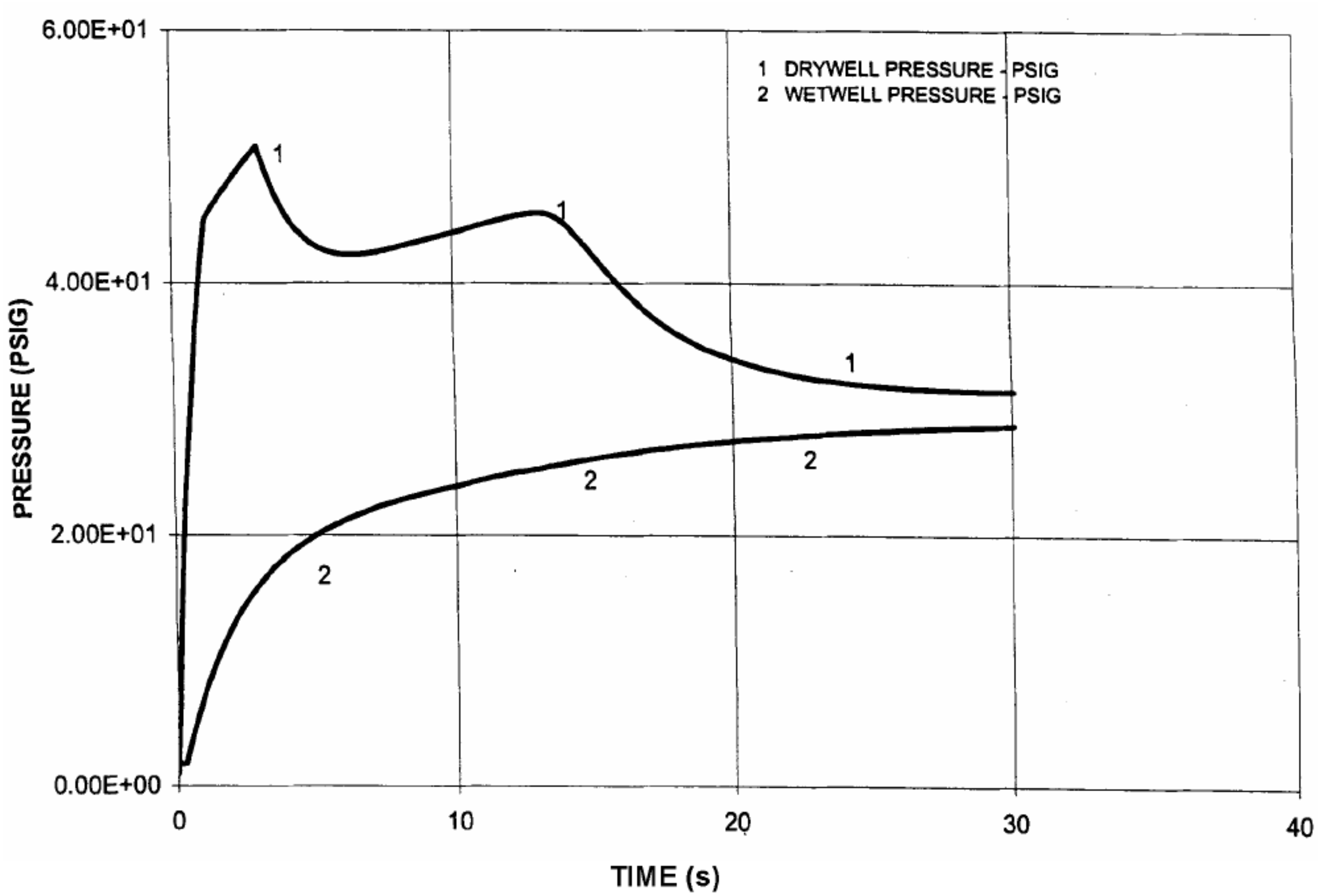
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTAINMENT RESPONSE TO DESIGN BASIS LOCA, ORIGINAL ANALYSIS

FIGURE 6.2-12



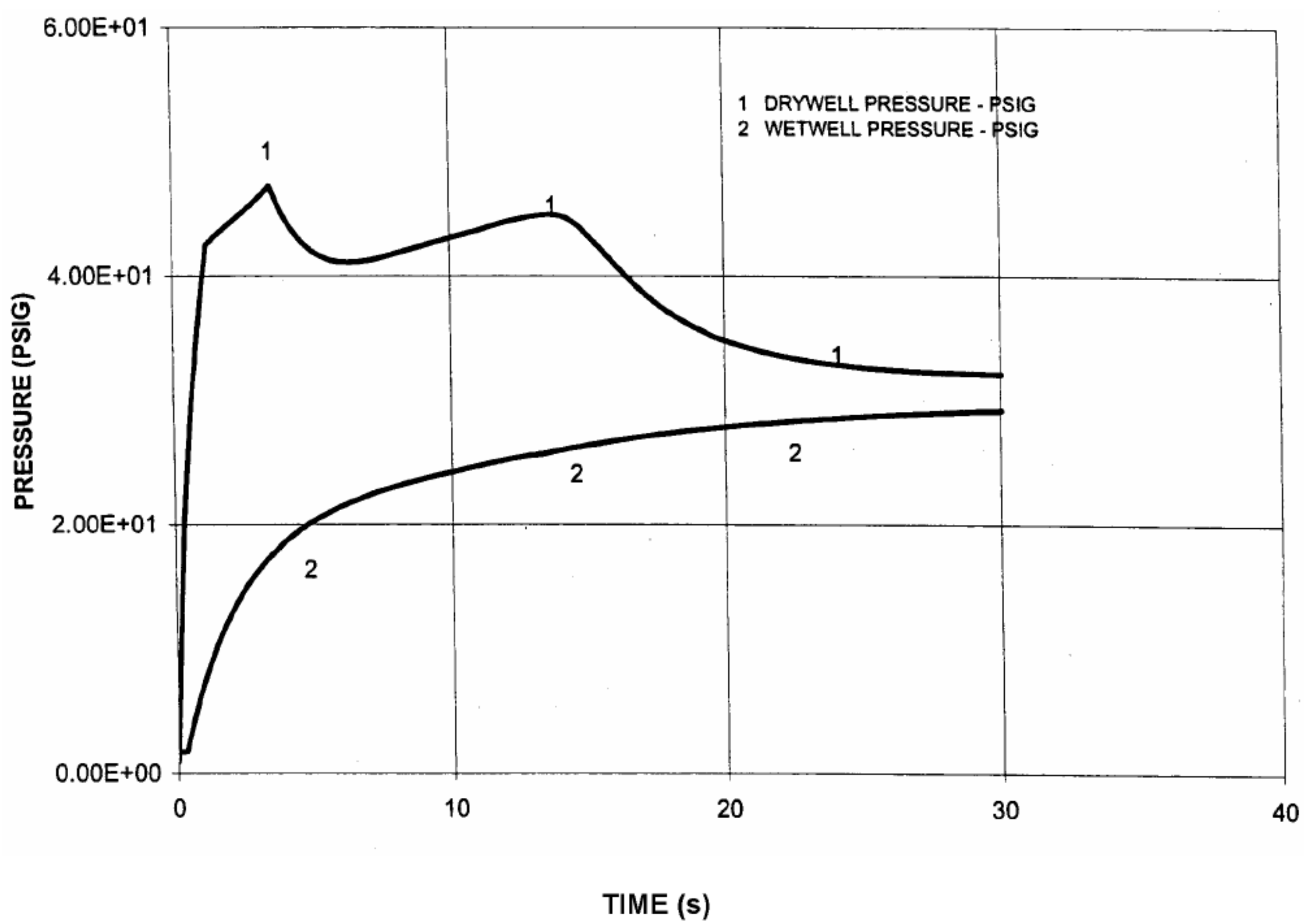
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTAINMENT PRESSURE RESPONSE TO DESIGN BASIS LOCA, OPERATION AT 100.5% OF RTP (2818 MWt)

FIGURE 6.2-17



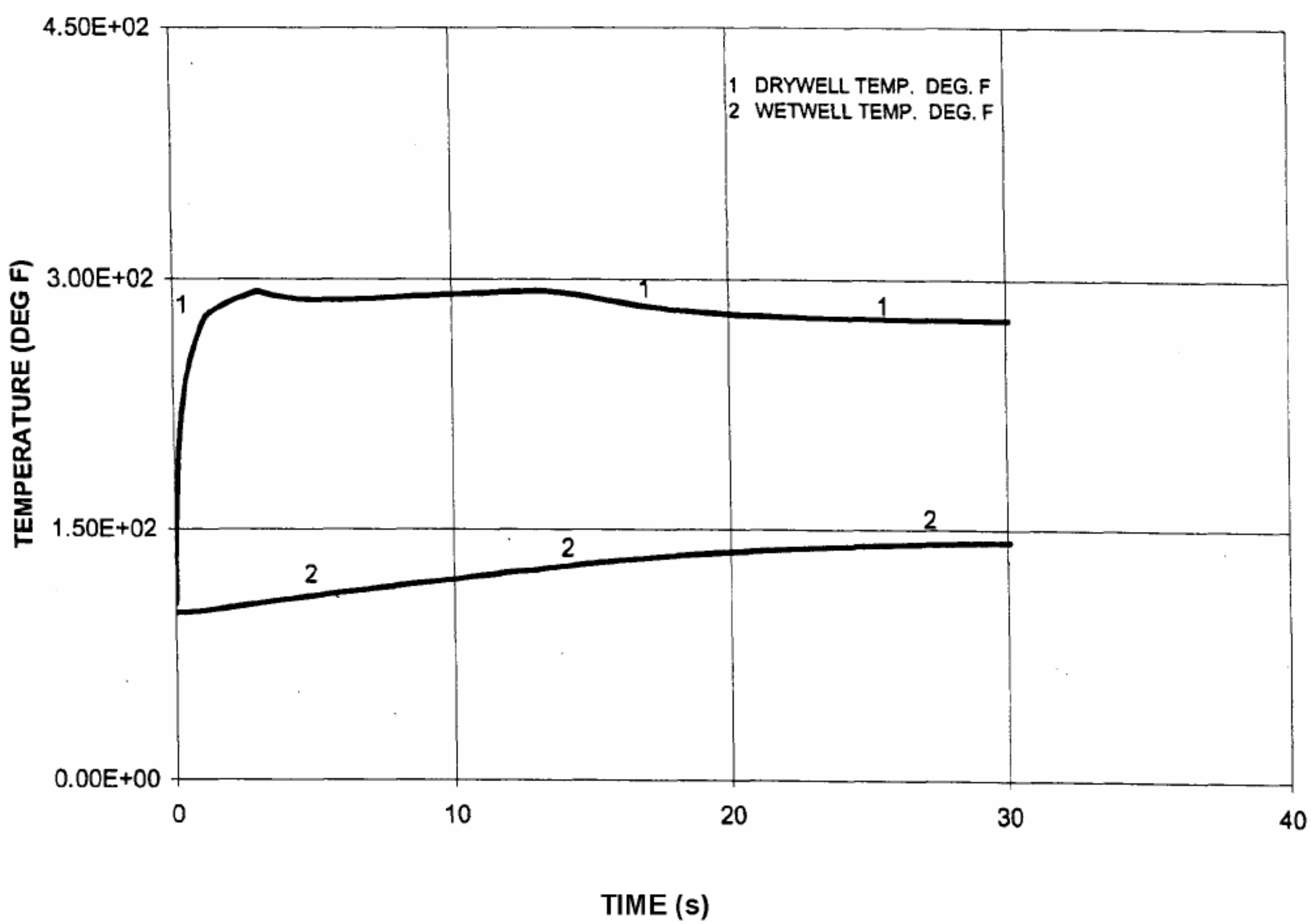
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTAINMENT PRESSURE RESPONSE TO DESIGN BASIS LOCA, OPERATION AT 100.5% OF RTP (2818 MWt)

FIGURE 6.2-18



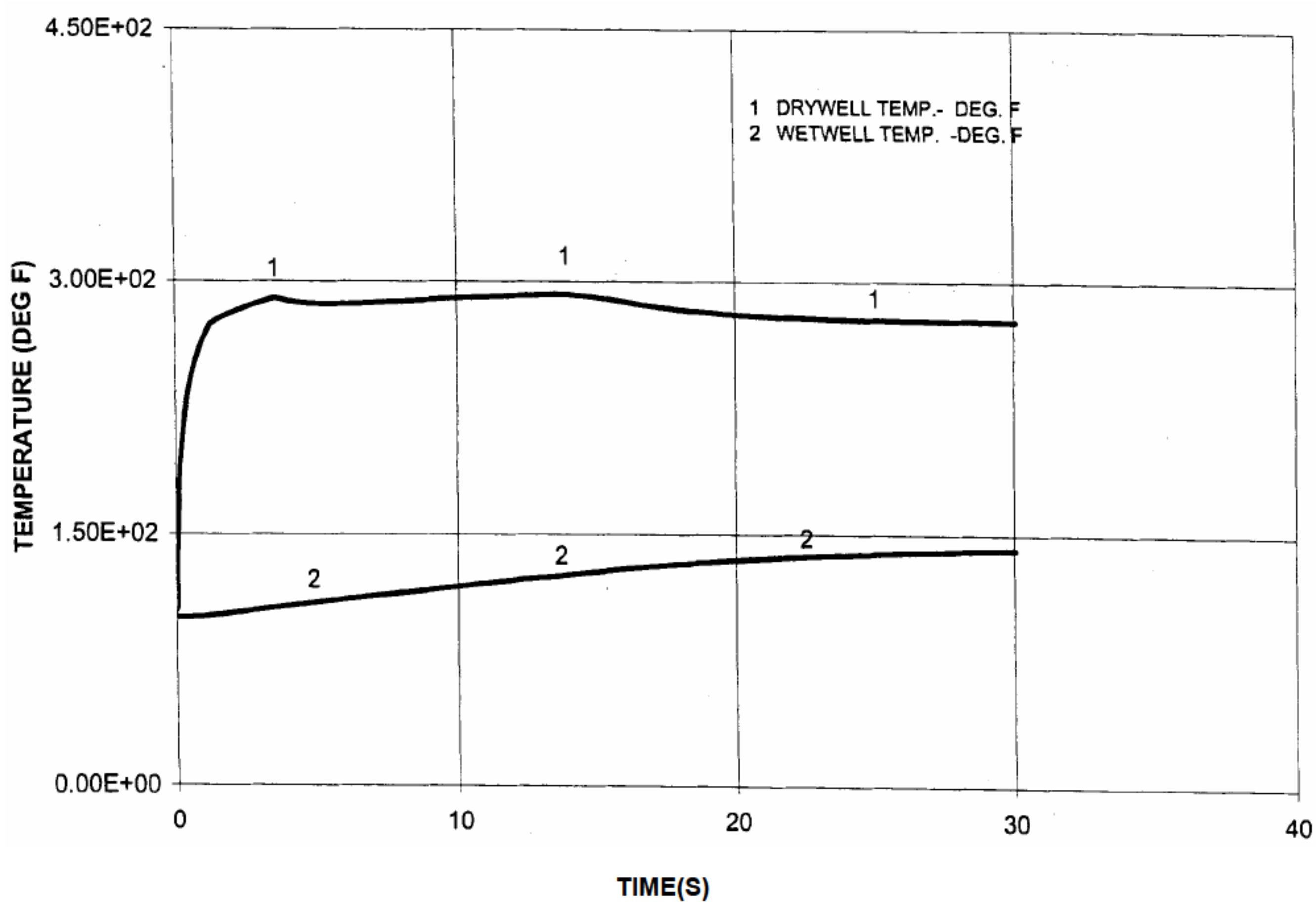
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTAINMENT TEMPERATURE RESPONSE TO DESIGN BASIS LOCA OPERATION AT 100.5% OF RTP (2818 MWt)

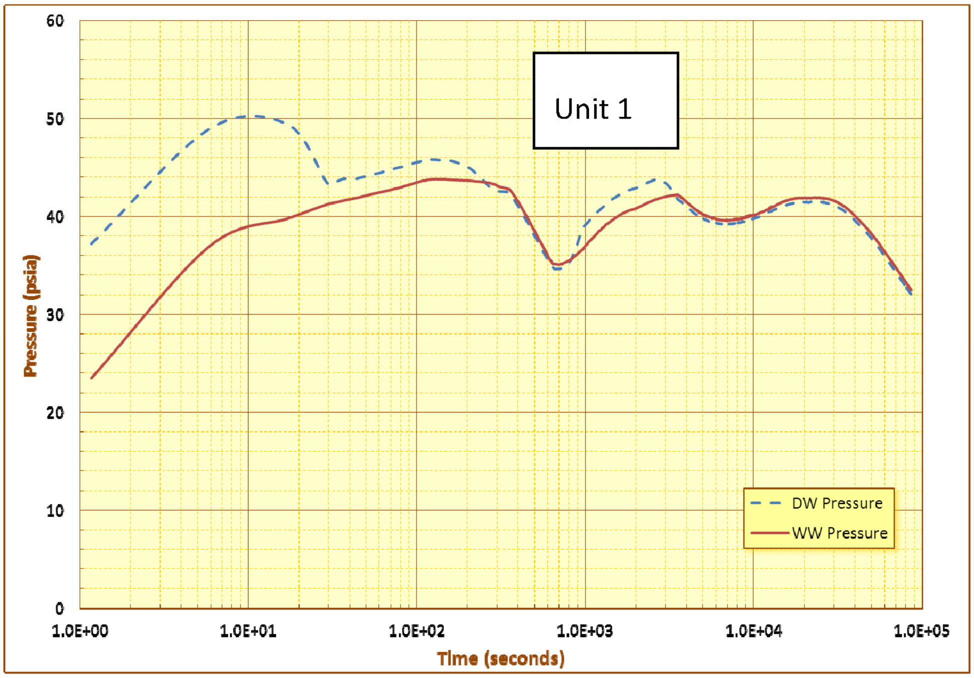
FIGURE 6.2-19

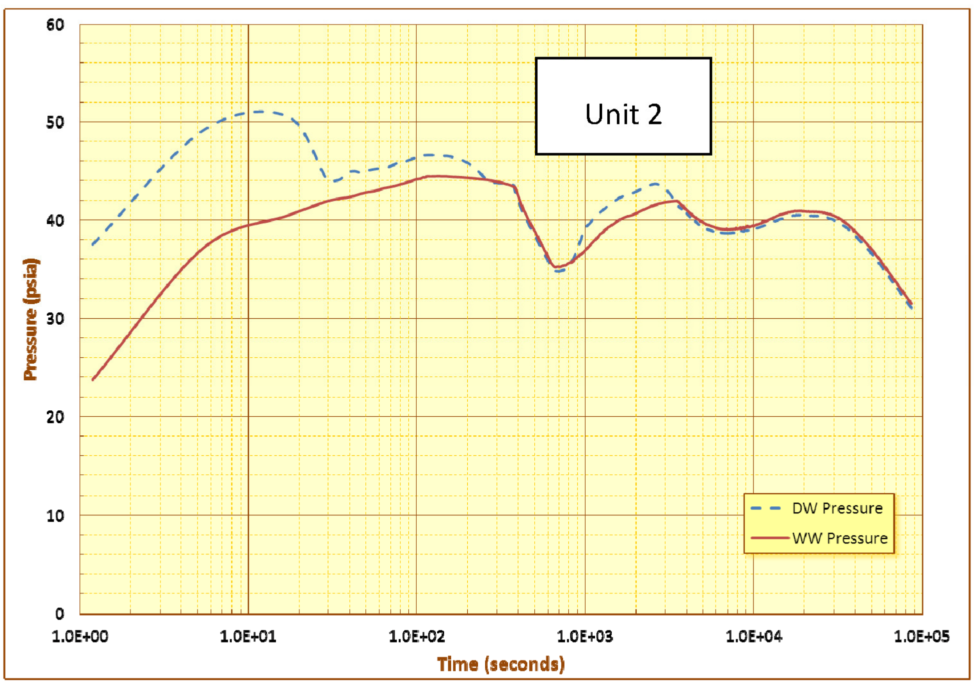


Hatch Unit 2 Short-Term Containment Response – Drywell/Waterwell Temperature vs Time

REV 22 9/04

SOUTHERN COMPANY *Energy to Serve Your World®*	**SOUTHERN NUCLEAR OPERATING COMPANY** **EDWIN I. HATCH NUCLEAR PLANT** **UNIT 2**	CONTAINMENT TEMPERATURE RESPONSE TO DESIGN BASIS LOCA OPERATION AT 100.5% OF RTP (2818 MWt) FIGURE 6.2-20





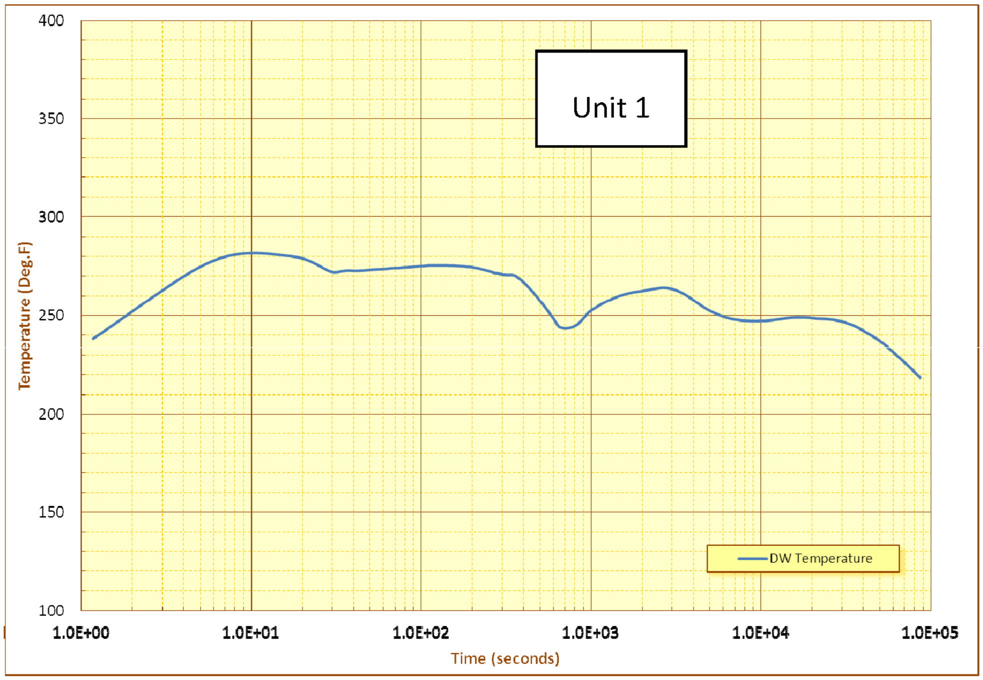
REV 30 9/12

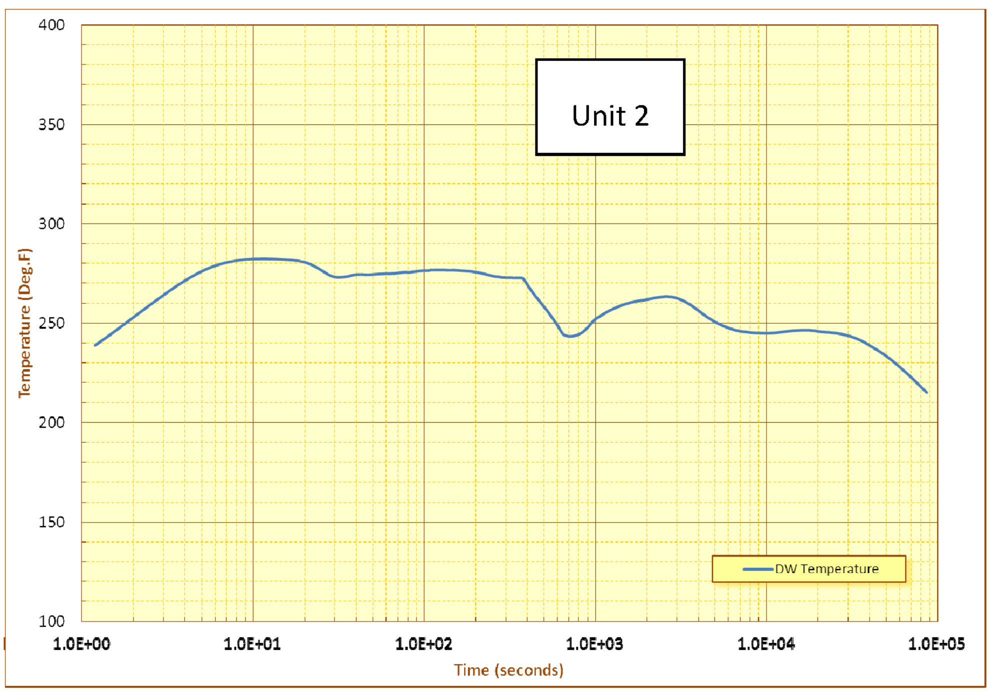
SOUTHERN COMPANY

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LONG-TERM RECIRCULATION LINE BREAK CALCULATED CONTAINMENT PRESSURE RESPONSE

FIGURE 6.2-21



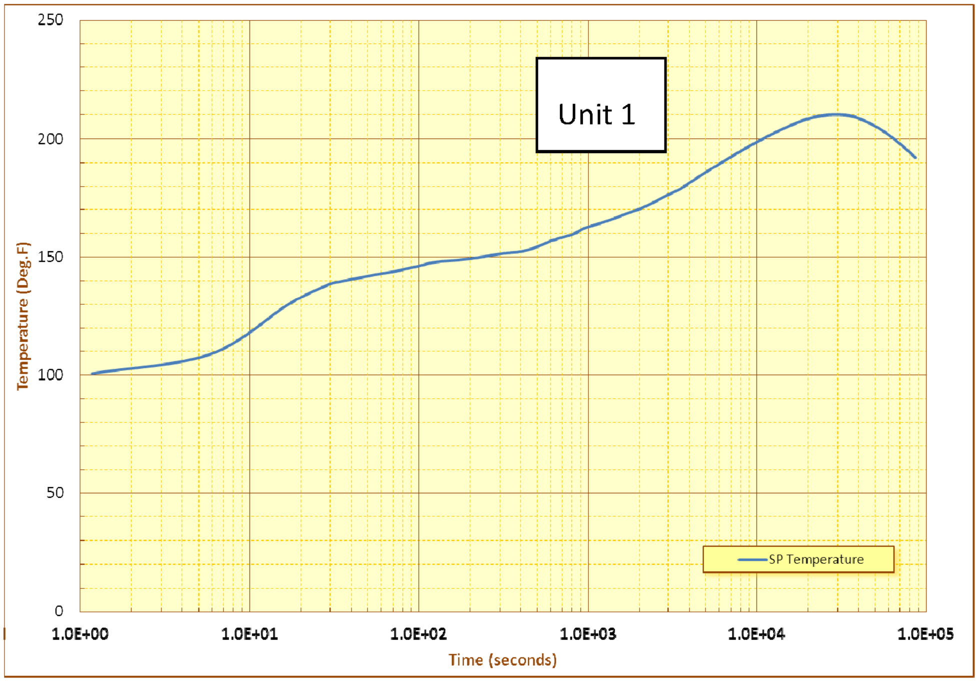


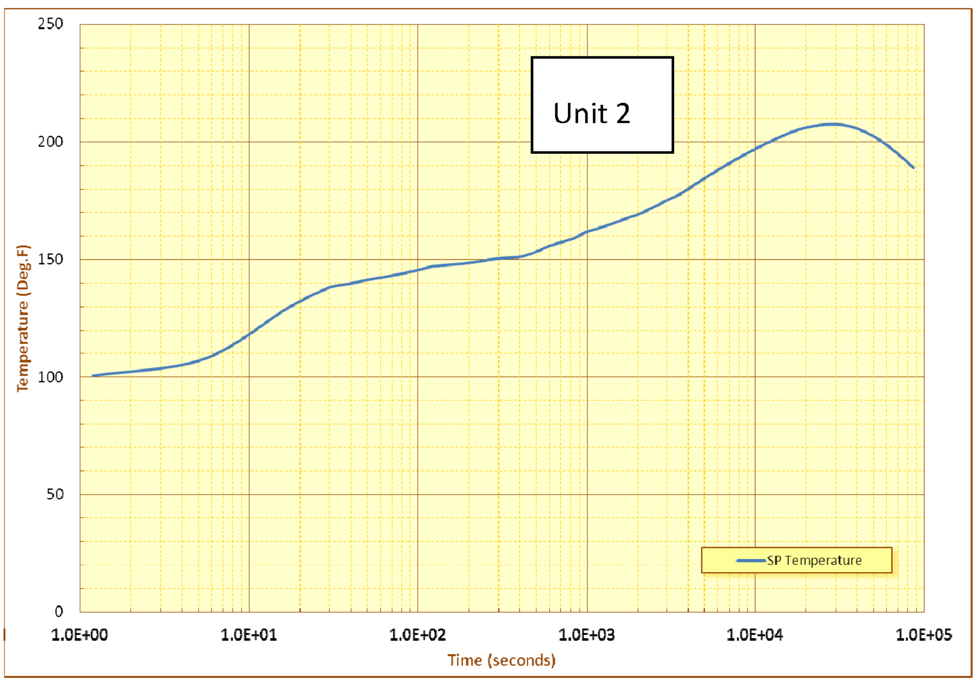
REV 30 9/12

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LONG-TERM RECIRCULATION LINE BREAK CALCULATED DRYWELL TEMPERATURE RESPONSE

FIGURE 6.2-22





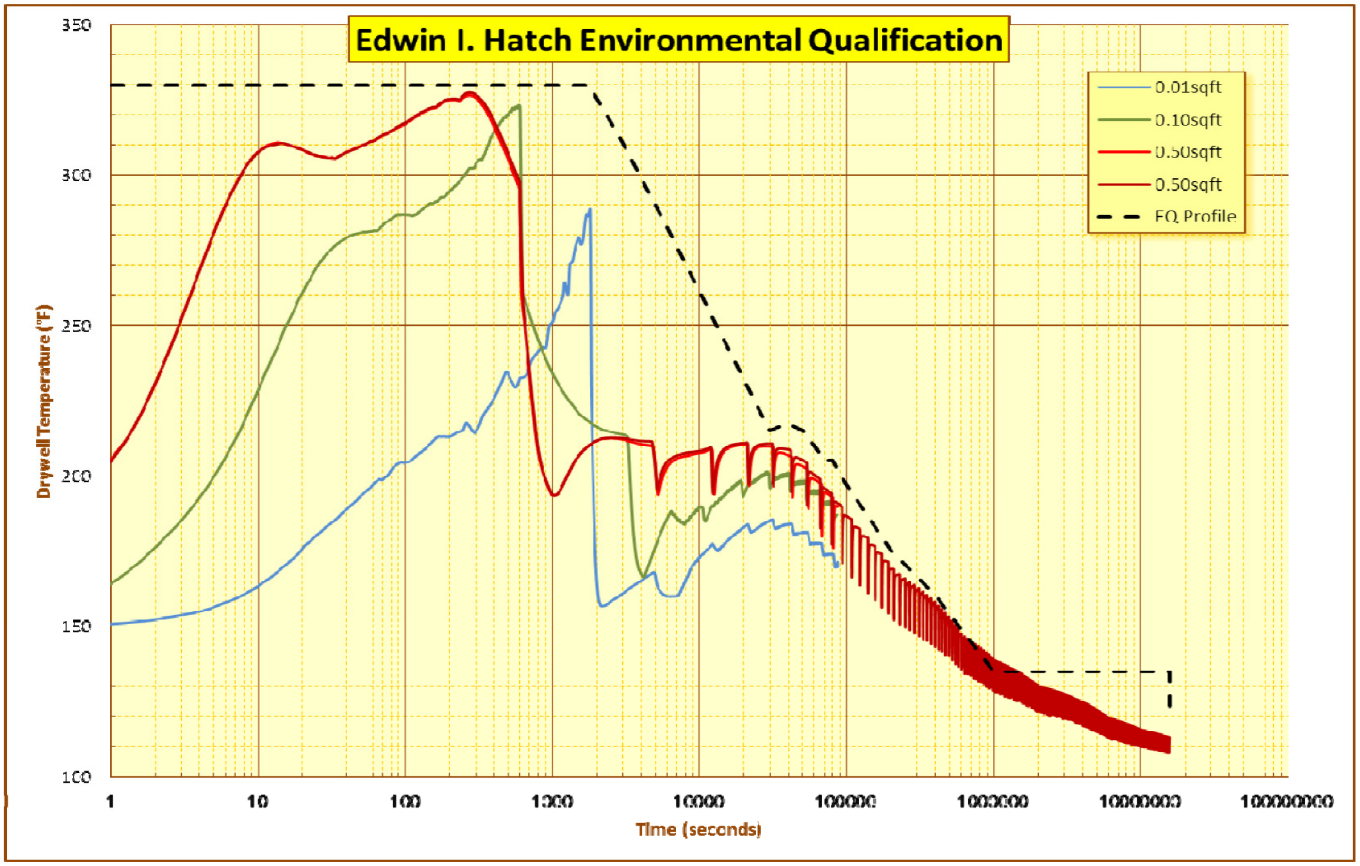
REV 30 9/12

SOUTHERN COMPANY

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

LONG-TERM RECIRCULATION LINE BREAK CALCULATED SUPPRESSION POOL TEMPERATURE RESPONSE

FIGURE 6.2-23



REV 30 9/12

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CONTAINMENT TEMPERATURE RESPONSE
FOR 0.01-ft^2 MSLBA

FIGURE 6.2-24

This figure has been deleted.

REV 30 9/12

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CONTAINMENT TEMPERATURE RESPONSE
FOR 0.1-ft^2 MSLBA

FIGURE 6.2-28

This figure has been deleted.

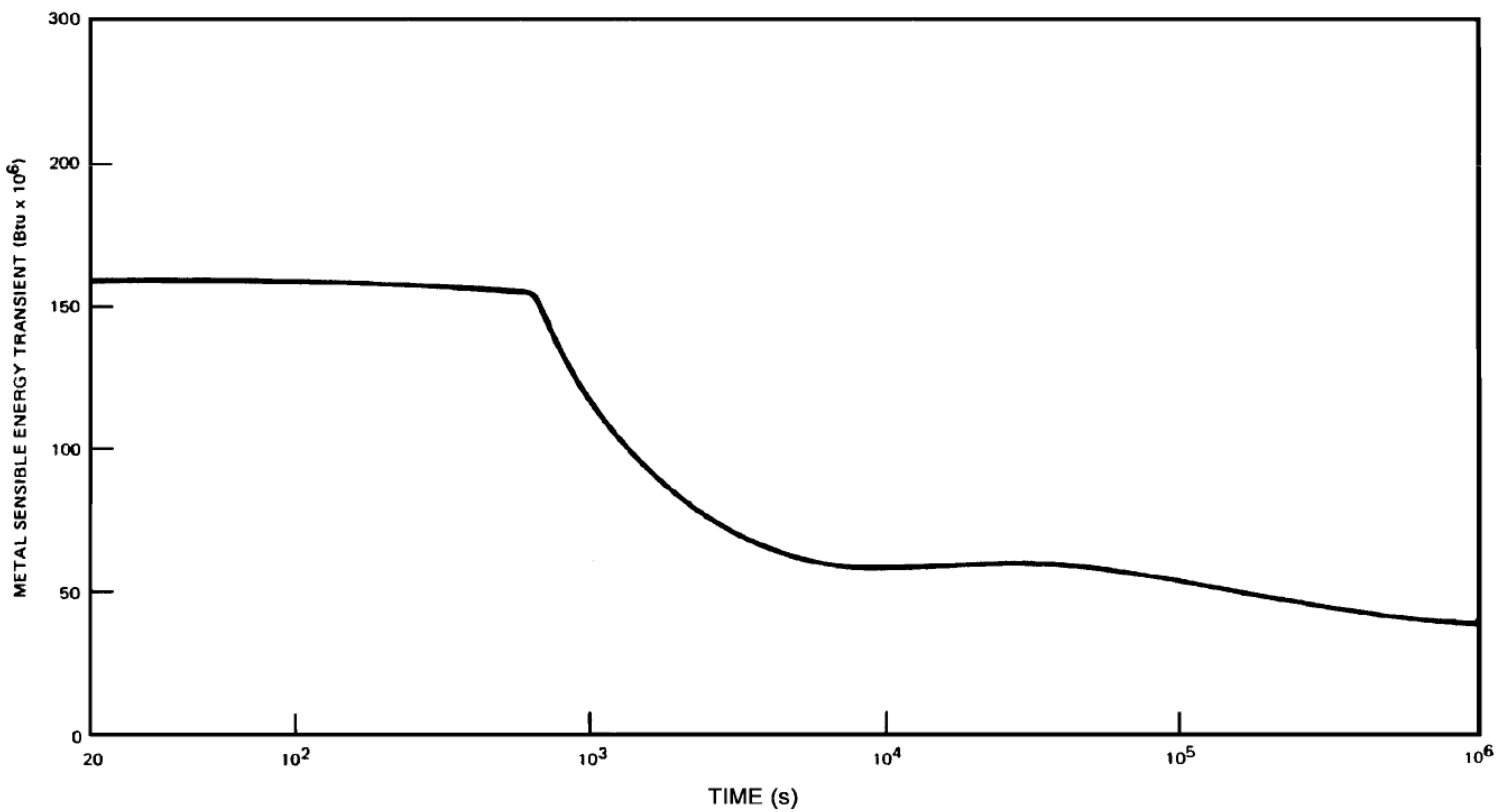
REV 30 9/12

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

CONTAINMENT TEMPERATURE RESPONSE FOR
0.5-ft^2 MSLBA

FIGURE 6.2-31



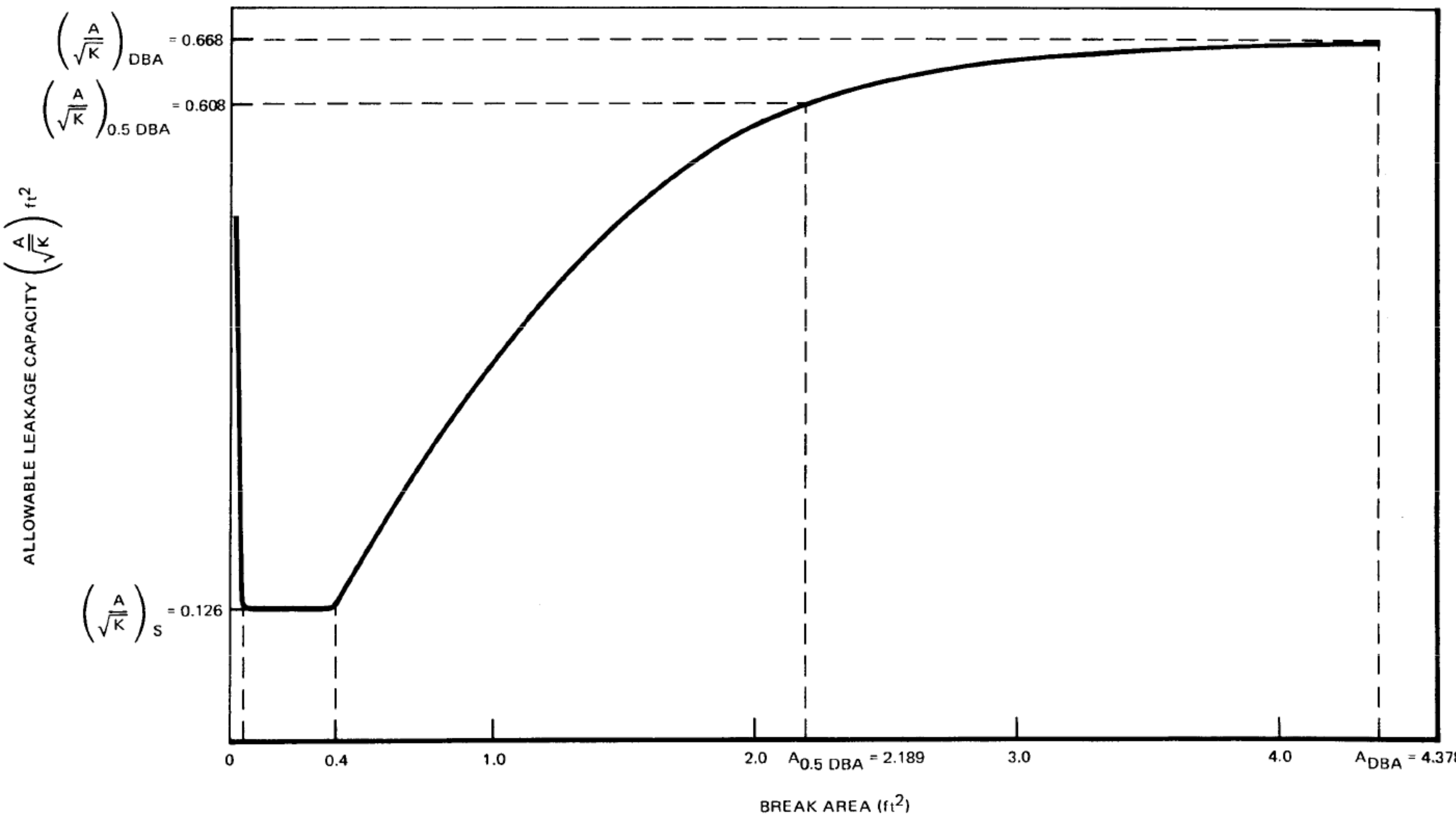
ACAD 2060226

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

SENSIBLE ENERGY TRANSIENT IN RPV AND INTERNALS
MINIMUM ECCS FLOW 95°F SERVICE WATER TEMPERATURE

FIGURE 6.2-34



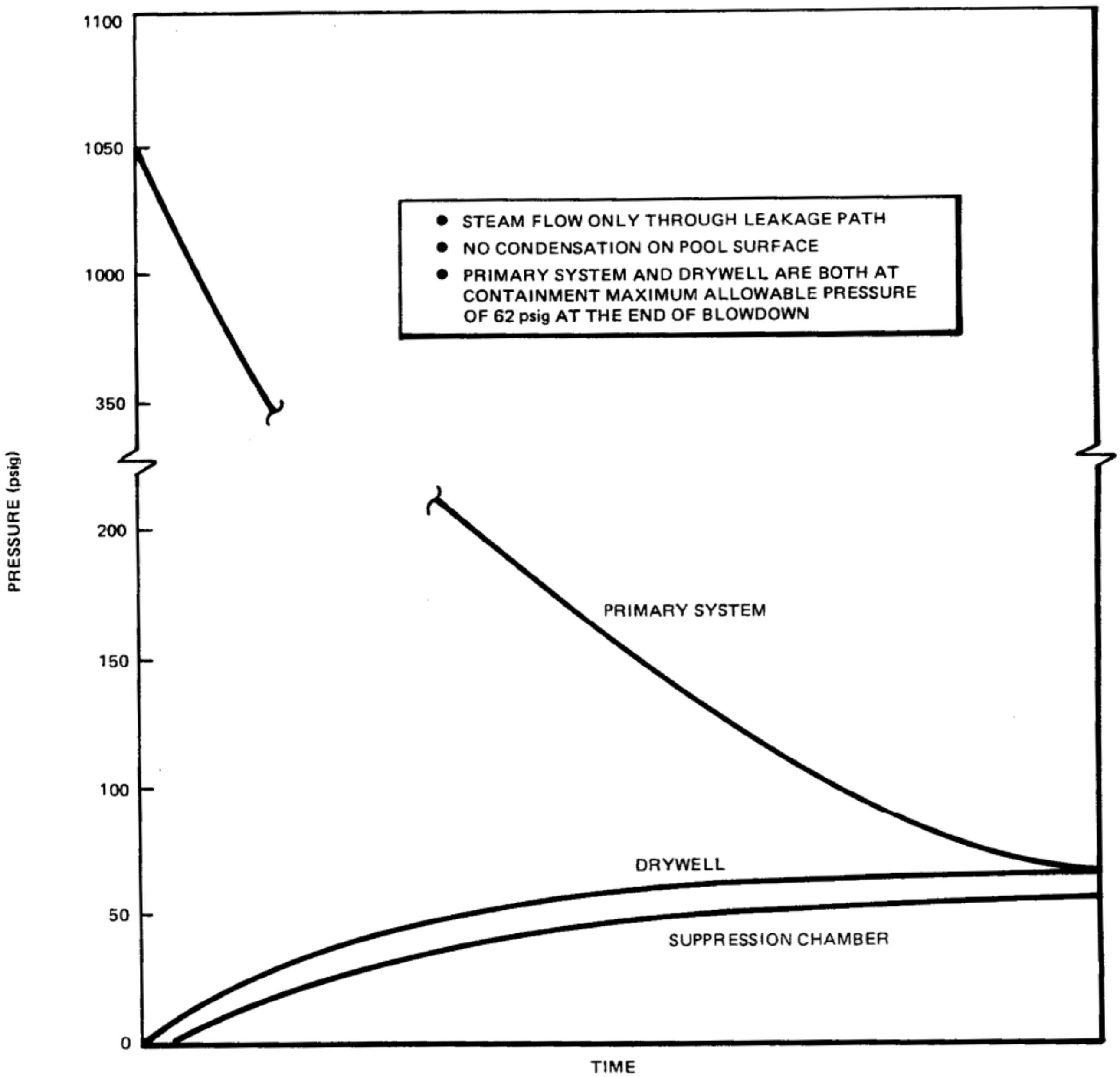
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ALLOWABLE LEAKAGE CAPACITY VERSUS BREAK AREA

FIGURE 6.2-35

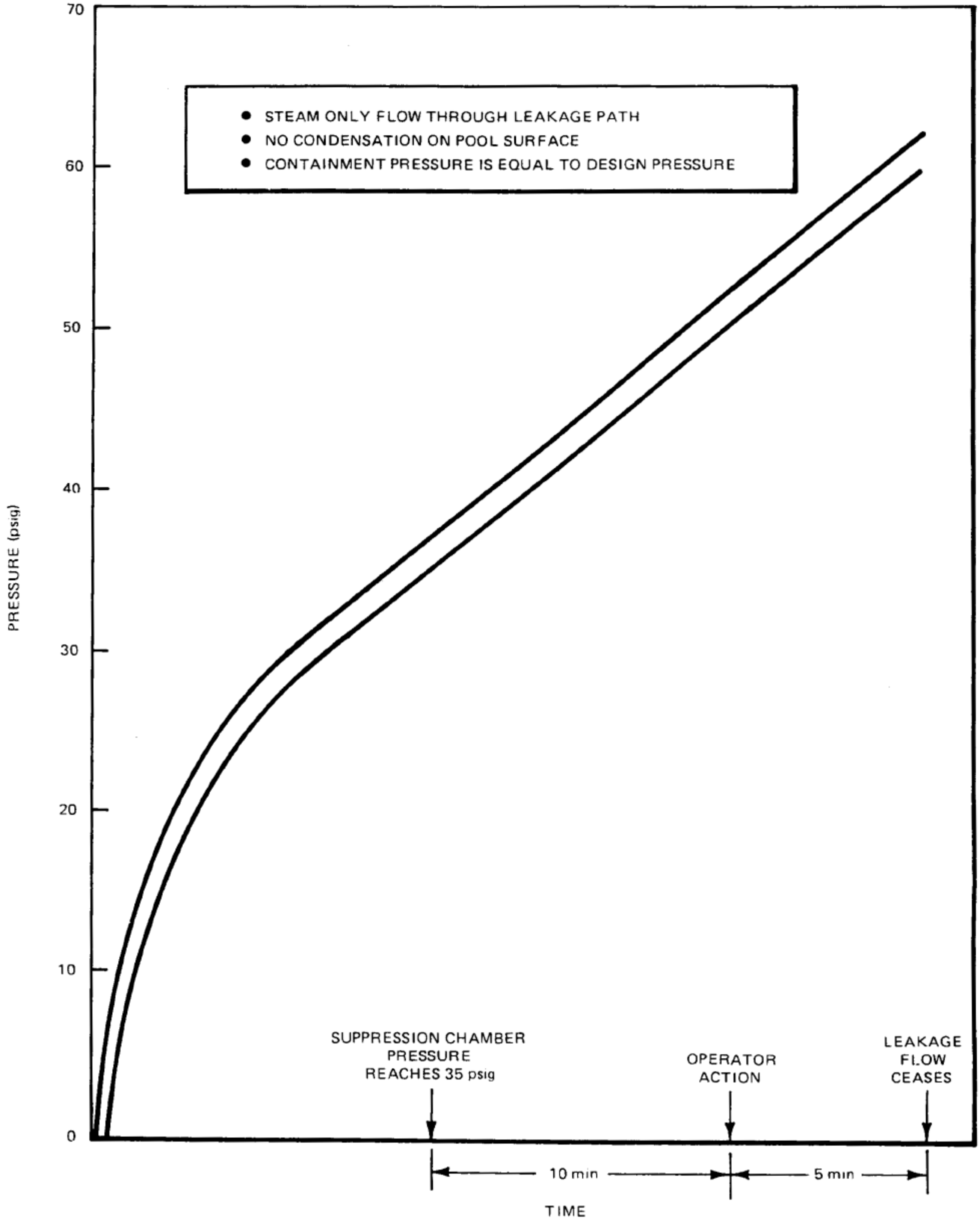


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTAINMENT RESPONSE TO LARGE PRIMARY SYSTEM BREAKS WHEN ALLOWABLE DRYWELL-TO-SUPPRESSION CHAMBER LEAKAGE CAPACITY EXISTS

FIGURE 6.2-36



REV 19 7/01

SOUTHERN COMPANY *Energy to Serve Your World®* **SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2**	CONTAINMENT RESPONSE TO SMALL PRIMARY SYSTEM BREAKS WHEN ALLOWABLE DRYWELL-TO-SUPPRESSION CHAMBER LEAKAGE CAPACITY EXISTS
	FIGURE 6.2-37

This figure has been deleted.

ACAD 2060230

REV 27 10/09

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC OF RECOMBINER SKID

FIGURE 6.2-49

This figure has been deleted.

ACAD 2060231

REV 27 10/09

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HYDROGEN RECOMBINER SYSTEM
PRESSURE PROFILE

FIGURE 6.2-50

This figure has been deleted.

ACAD 2060232

REV 27 10/09

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HYDROGEN RECOMBINER ANNUNCIATOR
PANEL ARRANGEMENT

FIGURE 6.2-51

This figure has been deleted.

REV 27 10/09

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIME-DEPENDENT HYDROGEN
CONCENTRATION WITH CGCS
(LONG TERM WITH RECOMBINATION)

FIGURE 6.2-52

This figure has been deleted.

REV 27 10/09

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIME-DEPENDENT CONTAINMENT HYDROGEN CONCENTRATION WITHOUT CGCS (NO RECOMBINATION)

FIGURE 6.2-53

This figure has been deleted.

REV 27 10/09

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIME-DEPENDENT HYDROGEN
CONCENTRATION WITH CGCS
(SHORT TERM WITH RECOMBINATION)

FIGURE 6.2-54

This figure has been deleted.

REV 27 10/09

REACTOR CORE AND SUPPRESSION POOL RADIOLYTIC GENERATION

FIGURE 6.2-55

This figure has been deleted.

ACAD 2060237

REV 27 10/09

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HYDROGEN RECOMBINER OPERATIONAL TEST LAYOUT

FIGURE 6.2-56

6.3 EMERGENCY CORE COOLING SYSTEM (ECCS)

Four ECCS subsystems protect the core against various sizes of hypothetical pipe breaks. Three subsystems inject emergency core cooling water into the reactor pressure vessel (RPV), and one subsystem depressurizes the RPV. The three injection subsystems are high-pressure coolant injection (HPCI), low-pressure coolant injection (LPCI), and core spray (CS). The fourth ECCS subsystem is the automatic depressurization system (ADS). The protection afforded by these subsystems meets the Nuclear Regulatory Commission (NRC) ECCS acceptance criteria of Title 10 Code of Federal Regulations (CFR) Part 50.46.

6.3.1 SAFETY DESIGN BASES

The objective of the ECCS, in conjunction with the primary and secondary containment, is to limit the release of radioactive material to the environs following a loss-of-coolant accident (LOCA) so that resulting radiation exposures are kept to a minimum and are within the guideline values given in 10 CFR 50.67.

6.3.1.1 Range of Coolant Ruptures and Leaks

The ECCS provides adequate core cooling in the event of any size break or leak in the piping of the nuclear system process barrier up to and including the double-ended break of the largest line connected to the RPV. The selection of break sizes and break locations is discussed in section 3.6 and supplement 15A.

6.3.1.2 Fission Product Decay Heat

In the event of a LOCA, the ECCS removes residual heat, including stored heat, heat from radioactive decay, and heat from the reactor core at a rate that limits the maximum fuel-cladding temperature to a value less than the 10 CFR 50.46 limit of 2200°F.

6.3.1.3 Reactivity Required for Cold Shutdown

The reactor is designed to be in the cold shutdown condition with the control rod of highest reactivity worth fully withdrawn and all other control rods fully inserted. A discussion of control rod functional design is provided in Chapter 4.

6.3.1.4 Capability to Meet Functional Requirements

The following functional requirements are met:

A. The ECCS has sufficient capacity, diversity, reliability, and redundancy to provide adequate cooling of the reactor core under anticipated operational occurrence (AOO) and accident conditions.

B. The ECCS is initiated automatically by conditions that sense the potential inadequacy of core cooling to limit the degree to which safety is dependent upon the operator.

C. The ECCS is capable of startup and operation regardless of the availability of offsite power supplies or the normal generator system of the plant.

D. Action taken to effect containment integrity does not negate the ability to achieve core cooling.

E. ECCS components within the RPV are designed to withstand the transient mechanical loadings during a LOCA without restricting the required core cooling flow.

F. ECCS equipment is designed to withstand the physical effects of a LOCA so that the core can be effectively cooled. Effects considered are missiles, fluid jets, pipe whip, high temperature, pressure, humidity, radiation, and seismic acceleration.

G. A reliable supply of water for the ECCS is provided. The source is located so that a closed cooling water path is established during ECCS operation.

H. The flowrate and sensing networks of each ECCS subsystem are testable during reactor shutdown. All active components required to operate during and after a LOCA are testable.

6.3.2 SYSTEM DESCRIPTION

The bounds within which system parameters must be maintained and the acceptable inoperable components are discussed in the Technical Specifications and the associated Bases, and the Technical Requirements Manual (TRM).

The aggregate of four separate ECCS subsystems is designed to protect the reactor core against fuel-cladding damage in excess of the limits set forth in the acceptance criteria of 10 CFR 50.46 for any line break accident.

The operational capability of the ECCS subsystems is designed to meet the functional requirements given in paragraph 6.3.1.4. Performance objectives are described in the following paragraphs.

During and after the first 10 min of ECCS initiation, the functional requirements are satisfied for all combinations of single active or passive component failures in the ECCS or its essential support system, and for single pipe breaks, including pipe breaks in any ECCS subsystem that can partially or completely disable that subsystem.

Long-term core cooling and containment cooling are provided by any one LPCI or CS pump delivering water to the RPV and by one residual heat removal (RHR) pump supported by one RHR heat exchanger with 100% water flow.

The power for ECCS operation is supplied from the essential ac power buses. These buses are normally energized from startup auxiliary transformer 2D, which is connected to the offsite power grid. If startup auxiliary transformer 2D fails, the essential buses are automatically transferred to startup auxiliary transformer 2C, which is also connected to the offsite power grid. (The two startup auxiliary transformers are connected to the offsite power grid by separate transmission lines.) If a loss-of-offsite power (LOSP) occurs, each of the three essential buses is connected to a diesel generator. The diesel generators are the onsite standby ac power sources and have sufficient capacity to meet all ECCS requirements. Since the diesel generators cannot be paralleled, loss of one diesel generator does not affect the operation of the other diesel generators.

One CS loop and one LPCI loop are powered by one division of the ac supply buses. The other CS loop and LPCI loop are powered from a second and separate division of the ac supply buses. Operation of either division is sufficient for ECCS performance.

All systems start automatically. The starting signal comes from independent and redundant sensors of high drywell pressure and low RPV water level. (Reference subsection 7.3.1 and section 7.8 for a discussion of ECCS instrumentation, and starting and control logic.)

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Piping and instrumentation diagrams for the subsystems and components that constitute the ECCS are provided and referenced under the discussion of the subsystem or component.

6.3.2.2 Equipment and Component Descriptions

The four ECCS subsystems (i.e., HPCI, automatic depressurization, CS, and LPCI) are described in this section with reference to the appropriate piping and instrumentation diagrams, and system process flow diagrams.

6.3.2.2.1 HPCI System

The HPCI system consists of a steam turbine that drives a constant-flow pump, system piping, valves, controls, and instrumentation. The HPCI system is shown in drawing nos. H-26020, H-26021, and S-25176.

The principal HPCI system equipment is installed in the reactor building. The turbine-pump assembly is located in a shielded area to ensure personnel access to adjacent areas is not restricted during operation of the HPCI system. Suction piping comes from the condensate storage tank (CST) and the suppression pool. Injection water is piped to the reactor feedwater pipe at a Tee connection. Steam supply for the turbine is piped from a main steam header in

the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the main control room (MCR). The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in subsection 7.3.1 and section 7.8.

The HPCI system ensures the reactor is adequately cooled to limit fuel-cladding temperature in the event of a small break in the nuclear system and a loss of coolant that does not result in a rapid RPV depressurization. The HPCI system permits the reactor to be shut down while maintaining sufficient RPV water inventory until the RPV is depressurized. The HPCI system continues to operate until RPV pressure is below the pressure at which either LPCI or CS system operation maintains core cooling.

If a LOCA occurs, the reactor scrams upon receipt of either a low RPV water level signal or a high drywell pressure signal. HPCI is automatically initiated. Upon receipt of a high RPV water signal, the HPCI system automatically stops. However, the LOCA ECCS analysis does not take credit for HPCI operation to ensure that 10 CFR 50.46 requirements are met.

The HPCI system is designed to pump water into the RPV for a wide range of pressures within the RPV. Two sources of water are available. Initially, the system uses demineralized water from the CST. Approximately 100,000 gal of the 500,000-gal CST are held in reserve for the HPCI and the reactor core isolation cooling (RCIC) systems. The value of 100,000 gal is based upon:

- The megawatt thermal rating of the plant.

- 100°F makeup water available from the CST (HPCI and RCIC system design criteria).

- The inventory loss due to the boiloff rate in the reactor for the 8-h integrated decay heat factor.

System demands on the CST other than the HPCI and RCIC systems draw from a tank internal standpipe. The inlet to this standpipe is set at a level so that ~ 100,000 gal are below the intake and unavailable to these other systems. The HPCI and RCIC systems connect separately to the CST near the bottom. In addition, the CST has a backup capacity from the 100,000-gal demineralized water storage tank. Should the CST be drawn down to a low level, automatic transfer to the suppression pool occurs. Water from either source is pumped into the RPV via a feedwater line. Flow is distributed within the RPV through the feedwater spargers, causing mixing with the hot water or steam in the RPV.

To ensure positive suction head to the pump, the pump is located below the level of the CST and below the water level in the suppression pool. Pump net positive suction head (NPSH) requirements are met by providing adequate suction head and adequate suction line size. Available NPSH is calculated using the assumptions of Regulatory Guide 1.1 (November 1970).

The location of the HPCI turbine-pump assembly and piping provides protection from the physical effects of design basis accidents (DBAs), such as pipe whip, flooding, and high temperature. The equipment is located outside the primary containment.

Steam from the RPV drives the HPCI turbine. Decay heat and stored heat generate steam extracted from a main steam header upstream of the main steam isolation valves (MSIVs). The two HPCI system isolation valves in the steamline to the HPCI turbine are normally open to keep piping to the turbine at elevated temperatures and permit rapid startup of the HPCI system. Signals from the HPCI control system open or close the turbine stop valve.

To prevent the HPCI steam supply line from filling with water, a condensate drainpot is provided upstream of the turbine stop valve. The drainpot normally routes condensate to the main condenser, but upon receipt of either a HPCI system initiation signal or a loss of control air pressure signal, isolation valves on the condensate line close automatically.

Two devices control turbine power:

A. A speed governor limits turbine speed to its maximum operating level.

B. A control governor with an automatic speed setpoint control is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCI system operation. When the governor is in the test mode, it can be operated manually; however, it is automatically repositioned by the demand signal from the flow controller if system initiation is required.

As reactor steam pressure decreases, the HPCI turbine throttle valve opens wider to permit passage of the steam flow required to provide necessary pump flow. The capacity of the system provides sufficient core cooling to prevent cladding melt while the pressure in the RPV exceeds that at which CS and LPCI become effective.

Exhaust steam from the HPCI turbine is discharged to the suppression pool. The HPCI steam piping from the primary containment to the outboard isolation valve (2E41-F003) is sloped so that any condensation in this piping section flows back into the piping inside the primary containment to a low-point drainpot in the HPCI steam piping immediately upstream of the inboard isolation valve (2E41-F002). The low-point drainpot and attached drain piping provide condensate removal during HPCI, RCIC, and main steamline (MSL) warmup. During unit startup, the HPCI steamline drain pot and the MSLs are drained by operation of the steamline condensate drain valves prior to opening the MSIVs. During plant operation, any condensation flows from the drain pot to the body drains from the inboard MSIVs and to the MSLs.

The standard practice of draining condensate from isolated steamlines prior to returning the steamlines to service eliminates water hammer problems.

The HPCI system turbine gland seals are vented to the HPCI system gland-seal condenser, and part of the water from the HPCI system pump is routed through the condenser for cooling purposes. Noncondensible gases from the gland-seal condenser are exhausted to the reactor building ventilation exhaust system. Under conditions of high radioactivity levels in the reactor building, this exhaust system is isolated and the gases are vented through the standby gas treatment system (SGTS).

A redundant system of check valves and isolation valves functions as a vacuum breaker line that connects the air space in the suppression pool with the HPCI turbine exhaust line. This eliminates any possibility of water from the suppression pool being drawn into the HPCI turbine exhaust line. The two isolation valves in series in this vacuum breaker line operate automatically by a combination of low RPV pressure and high drywell pressure. Test connections are provided on either side of the two check valves.

The system component classifications and additional requirements are described in subsection 3.2.2. The pump is designed and tested in accordance with the standards of the Hydraulic Institute.

Erosion, corrosion, and material fatigue were accounted for in the design of the HPCI system. Aging management programs (subsections 18.2.1, 18.2.6, 18.2.9, 18.2.12, 18.3.2, and 18.5.1) monitor the condition of the components so that actions are taken to provide reasonable assurance that the components are capable of performing their intended functions for 40 years and beyond.

Startup of the HPCI system is completely independent of ac power. For startup to occur, only dc power from the plant batteries and steam extracted from the nuclear system are required.

The maximum allowable time delay from the onset of actuating conditions for the initiating signal to injection valve wide open and rated flow availability is 75 s.

The HPCI system turbine is shut down automatically by any of the following signals:

A. Turbine overspeed prevents damage to the turbine and turbine casing.

B. RPV water level 8 indicates that core cooling requirements are satisfied.

C. HPCI pump low suction pressure prevents damage to the pump due to loss of flow.

D. HPCI turbine exhaust high pressure indicates a turbine or turbine control malfunction.

If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

HPCI pump discharge valves 2E41-F006 and 2E41-F007 are normally in the closed and open positions, respectively, as shown on drawing no. H-26020. HPCI initiation logic is designed to give 2E41-F007 an open signal upon initiation so both discharge valves may be in the closed position without affecting system operation.

Because the steam supply line to the HPCI system turbine is part of the nuclear system process barrier, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in subsection 7.3.1. However, the automatic depressurization and the low-pressure subsystems of the ECCS act as backup, and automatic shut off of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

Additionally, remote-manual startup, operation, and shutdown capabilities are provided. All automatically operated valves are equipped with a remote-manual functional test feature.

- HPCI system pump discharge shutoff valve.
- HPCI system steam supply shutoff valve.
- HPCI system turbine stop valve.
- HPCI system turbine control valve.
- HPCI system steam supply line drain isolation valves.
- HPCI system control loop valve.

The hydraulic oil pump must be started, and the hydraulic control system must be functioning properly before the turbine valve can be opened. The gland-seal condenser components must be operating to prevent outleakage from the turbine shaft seals. Startup of the equipment is automatic; however, its failure does not prevent the HPCI system from fulfilling its core cooling objective. When rated flow is established, the flow controller signal adjusts the setting of the control governor to maintain rated flow as nuclear system pressure decreases.

A minimum-flow bypass provides pump protection. The bypass valve automatically opens on a low-flow signal and automatically closes on a high-flow signal. When the bypass is open, the flow is directed to the suppression pool. A system test line provides recirculation to the CST during system test.

Shutoff valves are provided with proper interlocks that automatically close the test line upon receipt of a HPCI system initiation signal. The HPCI system is declared inoperable while in the test mode.

6.3.2.2.2 Automatic Depressurization System (ADS)

In case the capability of the feedwater pumps, control rod drive (CRD) pumps, RCIC system, and HPCI system is not sufficient to maintain the RPV water level, the ADS functions to reduce RPV pressure to a value low enough to allow LPCI and the CS system to pump water to the RPV in time to cool the core consistent with the design bases. The ADS, shown on drawing no. H-26000, is single-failure proof, thus ensuring the low-pressure systems can be actuated with a HPCI system failure and one additional single failure. The design, description, and evaluation of the SRVs are discussed in subsection 5.2.2. Subsection 7.3.1 provides a discussion of instrumentation and control.

The ADS uses 7 of the 11 safety relief valves (SRVs) to achieve the automatic blowdown to the suppression pool. The capacity of each relief valve is listed in table 5.2-4. The ADS dumps steam at a rate sufficient to ensure LPCI and the CS system adequately cool the reactor core.

To operate, the ADS control logic must have sensed high drywell pressure and RPV water levels 1 and 3 or a sustained RPV water level 1 signal after an approximate 13-min time delay with an RPV water level 3 signal. The logic starts the 120-s timer, and if a discharge pressure permissive signal is received, indicating that at least one LPCI or one CS pump is available, ADS will actuate. The 120-s time delay allows the HPCI system time to start.

However, an anticipated transient without scram (ATWS) event can generate the above initiation signals for ADS even though ADS is not required or desired. The operator can manually prevent ADS initiation during an ATWS event by using two keylocked switches in the MCR. This action enhances the standby liquid control (SLC) system effectiveness in shutting down the reactor during an ATWS event by allowing a minimum RPV water level to be maintained and preventing boron loss to the suppression pool.

Opening an SRV requires air pressure to the valve's diaphragm actuator. This air supply is controlled by a solenoid-operated pilot valve. The accumulator associated with the SRVs used with the ADS has sufficient capacity to allow for five operations of the pilot valves after the failure of the air supply to the accumulator. In the automatic depressurization function, the SRVs remain open after RPV pressure drops below the setpoint pressure.

Operability of the automatic SRVs was tested prior to installation in the reactor coolant system (RCS) and also during the plant preoperational test program. The SRVs are designed to allow removal for bench testing of the setpoints during shutdown.

6.3.2.2.3 CS System

The CS system (drawing no. H-26018 and process flow diagram S-25178) protects the core by removing decay heat following the postulated design basis LOCA. The CS system consists of two independent loops. Each loop includes one 100% capacity centrifugal water pump driven by an electric motor, a spray sparger in the RPV above the core, piping and valves that convey water from the suppression pool to the sparger, and associated controls and instrumentation. The CS system is shown on drawing no. H-26018.

The protection provided by the CS system also extends to a small break in which the feedwater pumps, CRD water pumps, RCIC system, and HPCI system all cannot maintain RPV water level, and the ADS operates to lower RPV pressure so LPCI and the CS system can provide core cooling.

The CS pumps, piping, valves, and support structures are designed in accordance with the criteria described in subsection 3.2.2. The CS piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the CS pump discharge. The outboard valve and piping downstream of the outboard shutoff valve are designed for RPV pressure and temperature. The pumps are also designed and tested in accordance with the standards of the Hydraulic Institute.

Either RPV water level 1 or high drywell pressure signals the automatic controls to energize the CS pumps, signals the locked-open suction valves from the suppression pool to open, and restores other system valves to the spray mode. When RPV pressure decreases, the CS

shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Subsection 7.3.1 gives further details and evaluation. The spray flowrate is sufficient to cool the core in time to limit fuel-cladding temperature. The same signals start LPCI, which operates independently to flood the RPV to achieve the same objective.

The motors in each CS loop are powered from the essential ac buses having a normal offsite source of power from startup auxiliary transformer 2D, which is backed up by startup auxiliary transformer 2C. In case of an LOSP, each essential bus is connected to a diesel generator.

Motor-operated valves (MOVs) of one CS loop receive power from one division, whereas MOVs of the other CS loop receive power from another division. Similarly, control power for each CS loop comes from different dc divisions.

The CS pumps and all automatic valves can be operated individually by manual switches in the MCR. Pressure indicators, flow meters, and indicator lights provide operating information in the MCR.

<u>Major Equipment for Identical Loops</u>

A. When the CS system is actuated, water is taken from the suppression pool. Flow then passes through an air-operated butterfly valve and through a motor-operated gate valve that is normally open but can be closed from the MCR by a remote-manual switch. Valve closure isolates the system from the suppression pool in the case of CS system leakage. The air-operated valve (AOV) is located in the CS pump suction line as close to the suppression pool as practical.

B. A local pressure gauge for each pump indicates the presence of a suction head for the pump. The two CS pumps are located in the reactor building below the water level in the suppression pool to ensure positive pump suction. Separation of the pumps, piping, controls, and instrumentation of each loop is such that any single physical event or missile generated by the rupture of any pipe in any system within the drywell cannot make both CS loops inoperable. The switchgear for each loop is located in a separate room for the same reason.

C. A vent line with one normally locked-closed valve is provided from the pump casing for filling the pump with water.

D. A low-flow bypass line runs from the pump discharge to below the surface of the suppression pool. The bypass valve opens automatically on a low-flow signal and closes automatically on a high-flow signal. The bypass flow is required to prevent the pump from overheating when pumping occurs against a closed discharge valve. An orifice limits the bypass flow.

E. A relief valve set for 500 psig protects the CS system upstream of the outboard shutoff valve from RPV pressure. The relief valve discharges to the radwaste system. CS piping upstream of the outboard shutoff valve is designed for the

lower pressure and temperature of the CS spray pump discharge. The outboard valve and piping downstream are designed for RPV pressure and temperature.

F. A full-flow test line admits circulating water to the suppression pool and allows the system to be tested during normal plant operation. A remote-manual switch in the MCR operates a normally closed MOV in the line. Partial opening of the valve and an orifice in the test line provide rated CS flow at a pressure drop equivalent to discharging into the RPV. A loop flow indicator located in the MCR signals that water is or is not flowing to the CS sparger or test line.

G. Two MOVs in each loop isolate the CS system from the nuclear system when the CS pump is not running. When signaled to open, these valves admit CS water to the RPV. To facilitate operation and maintenance, both valves are installed outside the drywell; however, they are placed as close to the drywell as practical to limit the length of line exposed to RPV pressure. The valve nearer the containment is normally closed for containment purposes. The outboard valve is normally open to limit the equipment needed to operate in an accident condition. A vent line located between the two shutoff valves can be used to measure leakage through the inside check valve or the inboard shutoff valve. To ensure containment integrity, the vent line is normally closed with two locked-closed valves.

H. A check valve in each CS pipeline inside the primary containment prevents loss of reactor coolant outside the containment in case the CS line breaks. A normally locked-open valve is provided downstream of the inside check valve to shut off the CS system from the reactor during shutdown to permit maintenance of the upstream valves. The two pipes in the CS system enter the RPV through nozzles located 180° apart. Each internal pipe then divides into a semicircular header with a downcomer at each end that turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to form two essentially complete circles, one above the other inside the shroud head. Short elbow nozzles are spaced around the spargers to spray the water radially onto the tops of the fuel assemblies.

6.3.2.2.4 LPCI Mode of RHR

In case of an RPV water level 1 or a high drywell pressure signal, the LPCI mode of the RHR system pumps water into the RPV in time to flood the core and limit fuel-cladding temperature.

LPCI operation protects the core in the event of a large break in the nuclear system when the feedwater pumps, CRD water pumps, RCIC system, and HPCI system are unable to maintain RPV water level.

LPCI protection also extends to a small break in which the feedwater pumps, CRD water pumps, RCIC system, and HPCI system cannot maintain RPV water level, provided the ADS operates to lower RPV pressure so LPCI and the CS system can provide core cooling.

Drawing nos. H-26014, H-26015, H-25104, and S-25140 show the process flow of the RHR system. LPCI operation consists of using four ac motor-driven centrifugal pumps that take water from the suppression pool and pump it into the two recirculation loops. The water enters the reactor through jet pumps and restores RPV water level.

An analysis was performed to determine the potential for LPCI pump runout, post-design bases LOCA. From the standpoint of maximizing LPCI pump flow following a LOCA, the most limiting configuration was quantitatively determined, by comparison of overall system resistance, to be the case where only one LPCI pump is operating into the broken recirculation loop. Also, the break was conservatively assumed to be at the LPCI connection to the recirculation piping; thus, no credit was taken for flow resistance of the recirculation system.

System resistance was calculated by assigning equivalent lengths of straight-pipe values to the various fittings and valves as given in Crane Company Technical Paper 410 and by extracting the lengths of piping runs from the physical piping drawings.

The pressure drop in psi per equivalent 100 ft is expressed by:

$$\Delta P / 100 = \frac{0.000336 fVM}{D^5}$$

where:

f = Friction factor.

V = Specific volume of the fluid.

M = Mass flowrate.

D = Pipe inside diameter.

The specific pressure drop of interest is the drop that occurs at a flowrate of 11,100 gal/min, which is the maximum allowable flowrate per pump. Using this equation, the existing system head loss at 11,100 gal/min for one LPCI pump operating into the broken loop is ~ 80 ft of water.

The pump vendor's certified performance curve was used to determine the pump total dynamic head of 290 ft of water at the maximum allowable flowrate of 11,100 gal/min. Therefore, the restricting orifice must add an additional 210 ft of water pressure drop to the system to match the pump total dynamic head.

Since the amount of downstream pressure recovery for an in-line restricting orifice is a function of the orifice beta ratio (orifice bore diameter to pipe inside diameter), the orifice bore required to give the desired system head loss, after pressure recovery, is found by using a convergency procedure with the pressure drop measured across the orifice as the trial argument and using the formula for liquid flow through nozzles and orifices from Crane Company Technical Paper 410. This procedure resulted in an orifice bore diameter of 7.56 in.

Preoperational testing verified LPCI's ability to perform in accordance with design requirements and demonstrated the orifices installed to limit pump flow are properly sized to perform their design function and do not restrict pump flowrates during LPCI operation.

A description of the LPCI mode of RHR preoperational testing is provided in supplement 14A, section 14A.22. A discussion of minimum ECCS availability is provided in paragraph 6.3.3.3.

Power for LPCI is supplied from the essential ac buses having a normal offsite source of power from startup auxiliary transformer 2D, which is backed up by startup auxiliary transformer 2C. In case of an LOSP, each essential bus is connected to a diesel generator.

The HNP-2 LPCI valve logic also provides for closing the valve in the reactor recirculation system (RRS) pump discharge side of the reactor recirculation loops.

LPCI pumps and piping equipment are described in subsection 5.5.7. Also described are other functions served by the same pumps if they are not needed for the LPCI function.

6.3.2.2.5 ECCS Discharge Line Fill System (Jockey Pump System)

One design requirement of any core cooling system is that cooling water flow to the RPV be initiated rapidly when the system is called on to perform its function. The jockey pump system ensures the ECCS discharge lines are full of water when the ECCS is required to be operable. This quick-start system characteristic is provided by quick-opening valves and quick-start pumps. By always keeping the LPCI and CS pump discharge lines full, the lag between the signal for pump start and the initiation of flow into the RPV can be minimized. If for some reason these lines are empty when the systems are called for, not only will the lag time be increased but also the lines will be subjected to unnecessarily large momentum forces associated with accelerating fluid into an empty pipe. However, even if the ECCS is initiated with the lines empty, the subsystems will still be capable of cooling the core within the guidelines as stated in subsection 6.3.1.

Since the core cooling pumps are located in the subbasement of the reactor building, ~ 92 ft below the point where the discharge piping enters the RPV, check or stop-check valves provided near the pumps prevent backflow from emptying the lines into the suppression pool. Past experience shows these valves leak slightly, producing a small backflow that eventually empties the discharge piping.

A jockey pump system, shown drawing no. H-26019, maintains a solid water level in the CS and RHR pump discharge lines, thereby eliminating the possibility of a severe water hammer when either system starts up. Two jockey pumps and their associated piping, valves, and instrumentation are provided for each division of the CS and RHR systems.

The pumps take suction from the suppression pool via the CS and/or RHR suction lines. Thus, the system remains operable when either line is isolated from the torus. Normally, the pumps are lined up to take suction from the CS suction line. The jockey pump system discharges to the RHR and CS systems at the discharge lines between the respective pump's discharge check valve and the normally shut discharge isolation valve. Each loop of the jockey pump

system incorporates an automatic-start feature for the nonrunning pump and has redundant instrumentation for monitoring system performance.

Prior to initial start of the RHR or CS system after maintenance, the discharge lines are filled by manually venting the high-point vents of the RHR and CS discharge lines while running a jockey pump in the associated loop. The running jockey pump remains in operation after initial filling of the lines, and the nonrunning pump is placed in the automatic-start mode.

Each pump has a bypass flow line with a restricting orifice to avoid having the pump run to a shutoff head while pressurizing the ECCS discharge lines and to facilitate testing the pump while it is isolated from the system. The bypass line recirculates to the suppression pool by way of the CS test line.

Continuous operation of a jockey pump after initial fill ensures the ECCS discharge lines remain full. If the running jockey pump should malfunction, a pressure switch starts the nonrunning pump when the pressure in the discharge header drops to a setpoint corresponding to the pressure exerted by the highest water column in the RHR and CS pump discharge lines.

The Technical Specifications require periodic testing to confirm the RHR and CS discharge lines are maintained full when the systems are required to be operable. If the discharge piping is found to be partially empty at the time of testing, the subsystem is inoperable per Technical Specifications.

Prior to performance of RHR or CS system surveillance involving start up of the pumps, system fill and vent are required by the surveillance procedure by referencing the applicable normal operating procedure. However, Technical Specifications require verification of filled discharge piping.

Redundant level-monitoring instrumentation provides a backup to the automatic-start feature of the jockey pump. This instrumentation consists of level switches 2E11-LS-N040 and 2E11-LS-N041 installed at the highest points of the RHR discharge lines (drawing nos. H-26014 and H-26015), 2E21-LS-N010 A&B installed at the highest point in each CS loop discharge line (drawing no. H-26018), and pressure switches 2E21-PS-N012 A&B installed in the jockey pump discharge headers. The pressure switch alarms when the pressure in the jockey pump discharge header drops to a predetermined pressure below the automatic-start setpoint. The level switches are installed so that the alarm is actuated at an elevation of 6 in. above the maximum elevation of the discharge piping. All alarms annunciate in the MCR.

Redundant check valves in the jockey pump discharge header isolate the jockey pump system from ECCS pressure when either the CS or RHR system is in operation.

The jockey pump system is Nuclear Class 2, Seismic Category I. The pumps are powered from essential ac power sources. The jockey pumps maintain the readiness of the safety-related ECCS to perform its safety-related function, but perform no active safety-related function during or following a LOCA.

The HPCI system is normally lined up to the CST and, therefore, does not require an inlet from the jockey pump system to maintain a full discharge line. The height of the water in the CST is

sufficient to maintain a full system up to the first isolation valve. The HPCI discharge line penetration is on the underside of the feedwater line and the first isolation valve is ~ 16 ft below the feedwater line. Therefore, feedwater flow keeps that portion of the HPCI discharge line full.

6.3.2.3 Applicable Codes and Classification

All ECCS subsystem piping and components comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment was procured. The ECCS subsystems are designed and constructed in accordance with Seismic Category I criteria in their entirety.

The LPCI mode of RHR, and the HPCI and CS systems are further divided into two classes.

A. The Class 1 portion of each system includes all piping and components that are part of the reactor system pressure boundary out to and including the second isolation valve.

   The Class 1 portions of the LPCI mode of RHR, HPCI, and CS systems are designed and constructed in accordance with Subsection NB of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, as specified in table 3.2-2.

B. The remaining portions of the LPCI mode of RHR, and the HPCI and CS systems are designated Class 2 and are designed and constructed in accordance with Subsection NC of the ASME Code, Section III, Nuclear Power Plant Components, as specified in table 3.2-2. The only exceptions to the foregoing are CS and RHR components supplied by General Electric (GE) and are designed and constructed in accordance with the ASME Code, Section III, Nuclear Power Plant Components (1968).

6.3.2.4 Material Specifications and Compatibility

Subsection 5.2.3 discusses general material considerations. Table 5.2-6 presents the specifications that generally apply to the selection of materials used in the ECCS. Nonmetallic materials, such as lubricants, seals, packings, paints, primers, and insulation, as well as metallic materials, are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and surroundings with concern for chemical, radiolytic, mechanical, nuclear radiation, and temperature effects.

6.3.2.5 Design Pressures and Temperatures

During several modes of ECCS operation, various design pressure and temperature inputs can be obtained from the information blocks shown on the following process flow diagrams:

- HPCI system - drawing no. S-25176
- CS system - drawing no. S-25178
- LPCI mode of RHR - drawing no. S-25140

The operational characteristics of the ADS valves are presented in subsection 5.2.2.

6.3.2.6 Coolant Quantity and Quality

The HPCI system normally takes suction from the CST, which is designed to retain a minimum reserve of approximately 100,000 gal for use by either the HPCI or the RCIC system. HPCI suction can be switched manually to the suppression pool at any time and is switched automatically upon either a CST low level or suppression pool high level signal. The suppression pool contains a maximum of ~ 677,360 gal of water. The CS system and LPCI take suction from the suppression pool.

The contents of the CST meet the water quality specifications for reactor-grade water. Any additions to the CST must meet these same specifications. In addition, the operational capability is provided so the contents of the CST can be processed through the condensate cleanup system to permit further cleanup as necessary. As a result, the water inventory in the CST available to the HPCI system in the event of a LOCA meets the water quality specifications of the RCS.

The contents of the suppression pool can be processed as described in subsection 9.3.7. Return water to the suppression pool is supplied from the CST. Water quality in the suppression pool is sampled and determined per plant procedures for conductivity, chlorides, pH, and other properties. No additives are made to the suppression pool water for water quality control during plant operation. Since no additives are used for core cooling and containment sprays, the engineered safety feature (ESF) materials of construction are compatible with the core cooling and containment spray water.

The residual heat removal service water system, described in subsection 9.2.7, serves as the ultimate heat sink.

6.3.2.7 Pump Characteristics

The HPCI pump is driven by a high-pressure turbine fed by reactor steam. The turbine is rated at 4100 hp at high speed (4000 rpm) and produces 750 hp at low speed (2025 rpm).

The CS system headflow characteristic is shown in figure 6.3-1. The pump is driven by an open, drip-proof, type-K, squirrel-cage induction motor rated at 1000 hp.

The RHR system headflow characteristic in the LPCI mode is shown in figure 6.3-2. Each pump is driven by a type-K, squirrel-cage induction motor. Three of the motors have a nameplate rating of 1000 hp; one has a rating of 1060 hp.

Power for the CS and LPCI pump motors is supplied from the essential buses. These pump motors are distributed on the essential buses as follows:

4160-V bus 2E:	CS pump 2A RHR pump 2A
4160-V bus 2F:	RHR pump 2C RHR pump 2D
4160-V bus 2G:	CS pump 2B RHR pump 2B

Availability of any two of the three essential buses is sufficient for a safe shutdown (tables 8.3-11 through 8.3-16 and figure 8.3-8).

6.3.2.8 Heat Exchanger Characteristics

No heat exchangers in the closed cooling water path are associated with the ECCS subsystems. The heat exchangers in the RHR system are discussed in subsections 5.5.7 and 6.2.2.

6.3.2.9 ECCS Pump Suction Strainers

The original LPCI and CS pump suction strainers were replaced with larger capacity strainers. The new strainers are large enough that adequate NPSH is available at all pump operating conditions, with all the debris assumed to reach the suppression pool, coating the strainers. The basis for the GE method used to size the LPCI and CS system pump strainers was developed by the Boiling Water Reactor Owners Group (BWROG) ECCS Suction Strainer Committee after exhaustive testing, study, and evaluation of available data. The methodology included determination of the LOCA break location, size of the debris destruction zone, percentages of insulation and volume of other debris transported to the suppression chamber, and sludge volume.

Based on the thermal power optimization (TPO) and reactor operating pressure increase (ROPI) evaluations[7, 8], it was determined that adequate NPSH margins exist for the RHR and CS pumps post-LOCA for Units 1 and 2.

6.3.2.10 ECCS Flow Diagrams

Drawing nos. S-25140, S-25141, S-25176, and S-25178 are process flow diagrams that present flowrates, temperatures, and pressures of the various ECCS subsystems. These parameters are presented for several modes of operation, including LOCA and test conditions.

6.3.2.11 Relief Valves and Vents

The LPCI mode of RHR and the CS system are not designed to withstand normal reactor system pressures. Although isolation system designs make such occurrences very unlikely (paragraph 6.3.2.15), relief valves protect these subsystems from possible overpressurization resulting from leaking valves. Pressurized portions of the HPCI system are designed for service at RPV pressure and, therefore, do not require overpressurization protection.

Relief valves accomplishing reactor system-originated overpressurization protection include the following:

Valve	Line Protected	Capacity	Setpoint
E21-F012A&B	CS pump discharge line	100 gal/min	500 psig
E11-F025A&B	LPCI pump discharge line	50 gal/min	400 psig
E11-F029	RHR pump shutdown cooling mode suction line	35 gal/min	200 psig

6.3.2.12 System Reliability

Reliability models were constructed for alternative ECCS configurations, and a comparative study yielded the most reliable system configuration. Upon completion of the final design, a formal reliability analysis was performed to:

- Determine the expected system availability (average reliability).
- Set safe system test intervals and allowable repair times.
- Quantitatively evaluate the system for conformance to the original design concepts, as well as to existing industry standards and criteria for reactor protection and safety systems.

System availability was evaluated at selected test intervals, and allowable repair times were determined by well established reliability/availability methods. Qualitative analysis includes a functional system failure modes and effects analysis, the results of which are used to verify conformance to industry criteria, develop reliability models, and ensure original design redundancy and diversity are retained.

Availability, as applied to the ECCS, is defined as the probability the system is operable when required. ECCS availability is a function of the component system test intervals and the failure rates of component parts used in the system. Component parts used in the ECCS have low failure rates as evidenced by historical field operating experience. ECCS availability required to ensure adequate plant safety is established as a system design requirement. To ensure adherence to the availability design requirement, the periodic test intervals and allowable repair times for inoperable systems are defined in the Technical Specifications.

The power sources required for successful system operation are arranged in redundant configurations so that the power availability is not a limiting factor in determining the overall system success probability.

6.3.2.13 Protection Provisions

ECCS piping and components are designed to accommodate the effects of movement, missiles, thermal stresses, a LOCA, and the design basis earthquake (DBE).

The reactor coolant pressure boundary (RCPB) was analyzed for four categories of design transients: normal, upset, emergency, and faulted conditions. These categories are generally described in the ASME Code, Section III, 1968 Edition N412. Subsection 5.2.1 provides additional details of this analysis.

Protection of the mechanical, instrumentation, and electrical portions of the ESF and reactor protection systems against environmental conditions is discussed in section 3.11.

Paragraph 6.3.2.2.5 describes the features protecting against water-hammer effects in ECCS discharge lines. Section 3.4 describes design protection against water flooding. Separation barriers, pipe whip restraints, or energy-absorbing materials protect the ECCS against the effects of pipe whip. One or more of these three methods are applied to protect against cascading damage to ECCS piping and components that could otherwise result in a reduction of ECCS effectiveness to an unacceptable level. Section 3.6 describes the design protection and analysis performed for pipe whip.

ECCS piping and components located outside the containment are protected from internally and externally generated missiles by the reinforced concrete structure of the ECCS pump rooms. In addition, the watertight construction of the ECCS pump rooms below grade level protects against damage from flooding. Section 3.5 describes design protection against postulated missile damage.

6.3.2.14 MOVs and Controls

The LPCI mode of RHR and the CS system are not designed to withstand reactor system pressures; therefore, to ensure these ESFs are not subjected to damaging pressures, appropriate relief valves discussed in paragraph 6.3.2.11 and isolation valves with system interlocks and alarms discussed below are provided. Section 7.3 provides further discussion of the controls for these valves.

LPCI is isolated from the RCPB by the following:

Valve	Line Isolated	Isolation Signal
2E11-F008	Shutdown suction	PIS 2B31-N679D high pressure
2E11-F009	Shutdown suction	PIS 2B31-N679A high pressure

2E11-F015A&B	Pump discharge	PIS 2B31-N679A&D high pressure
2E11-F017A&B	Pump discharge	PIS 2B21-N690A,B,C,&D high pressure
2E11-F050A&B	Pump discharge	(Check valve)

If either pressure transmitter 2B31-N079A or D fails, or either trip unit (PIS) 2B31-N679A or D fails, the system is still protected; because the other sends a close signal to valves in series with the valves controlled by the failed switch. In the event of valve leaks, the system is protected by the pressure relief valves as outlined in paragraph 6.3.2.11.

The CS system is isolated from the RCPB by the following:

Valve	Line Isolated	Logic
2E21-F006A&B	Pump discharge	Check valve
2E21-F004A&B	Pump discharge	Remote manual switch (RMS) - no interlock
2E21-F005A&B	Pump discharge	RMS - no interlock

Check valves are backed up by normally closed MOVs. In the event of operator failure and check valve leaks, the system is protected by relief valves as outlined in paragraph 6.3.2.11.

6.3.2.15 Materials

Materials used for ECCS equipment and components are reviewed and evaluated relative to radiolytic and pyrolytic decomposition, and attendant effects on safe ECCS operation. For example, fluorocarbon plastic (Teflon) is not permitted in environments that obtain temperatures > 300°F or radiation exposures above 10^4 rads.

The organic materials used in the primary and secondary containments (paragraphs 3.8.2.7 and 3.8.4.6) were selected for extended life during normal operation and for their resistance to expected accident environmental conditions. Thermal insulations used are inorganic and are not sensitive to high-radiation fields, steam, or high temperature. All exterior surfaces of carbon steel components are treated with an inorganic zinc primer. All paints used are high-temperature types.

Evaluation of these materials determined they satisfactorily ensure accident environmental conditions and their expected products of decomposition, if any, do not adversely affect the operability of any ESF.

6.3.2.16 Instrumentation Requirements (HNP-1 and HNP-2)

The ECCS instrumentation requirements described herein are applicable to HNP-1 and HNP-2 unless specified otherwise. The design and logic of the instrumentation for the ECCS is

discussed in HNP-1- and HNP-2-FSAR subsection 7.3.1, HNP-1-FSAR section 7.18, and HNP-2-FSAR sections 7.5 and 7.8.

The following instrumentation is available in the MCR to assist the operator in accurately assessing the post-LOCA conditions if one should occur:

- RPV water level.
- RPV pressure.
- Drywell pressure.
- Drywell temperature.
- Suppression pool level.
- Suppression pool temperature.
- Suppression pool pressure.
- LPCI flow and pressure.
- CS flow and pressure.
- HPCI flow and pressure.

RPV water level trips or drywell high pressure automatically actuate HPCI, CS, and LPCI. In addition, each system can be manually actuated from the MCR.

The ADS is automatically actuated when RPV water levels 1 and 3 are coincident with high drywell pressure or if an RPV water level 1 signal is present after an approximate 13-min time delay coincident with an RPV water level 3 signal. A time delay is incorporated as discussed in chapter 7. In addition, a discharge pressure permissive signal from one CS or one RHR (LPCI) pump must be available. The ADS can also be manually actuated from the MCR.

In the event of an anticipated transient without scram (ATWS), ADS operation can be manually inhibited. This enhances SLC system effectiveness by allowing a minimum RPV water level to be maintained and by preventing boron loss to the suppression pool. This mode of operation is described in HNP-1-FSAR paragraph 7.4.3.3.2 and HNP-2-FSAR paragraph 7.3.1.2.2.

6.3.2.17 Tests and Inspections (HNP-1 and HNP-2)

The tests and inspections described herein are applicable to HNP-1 and HNP-2 unless specified otherwise.

6.3.2.17.1 General

Each active component of the ECCS required to operate in a DBA is designed to be testable.

The HPCI system, ADS, and CS system have no normal process uses and, therefore, are tested periodically to assure the ECCS operates to effectively cool the reactor core in an accident. The four LPCI pumps can be placed in use as part of the RHR system and, if so, their status is known from normal process uses. However, the LPCI pumps are tested no less frequently than the rest of the ECCS.

Other parts of the LPCI system, such as the two injection check valves inside the primary containment drywell and the four shutoff valves outside the drywell, are intended for use only in an accident and are tested periodically in accordance with the inservice testing program.

Preoperational tests of the ECCS were conducted during the final stages of plant construction prior to initial startup to ensure proper functioning of all controls and instrumentation, pumps, piping, and valves. System reference characteristics, such as pressure differentials and flowrates, documented during the preoperational tests are used as base points for measurements obtained in the subsequent operational tests.

During plant operation, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the RPV is open for refueling or other purposes, the spargers and other internals can be inspected. The testing frequencies of most ECCS components are correlated with the testing frequencies of the associated controls and instrumentation. When a pump or valve control is tested, the operability of the pump or valve, and the associated instrumentation is also tested by the same action.

When the ECCS is tested, operation of most the components is indicated in the MCR. Special test provisions are used for components requiring local observation.

Relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments. Bench tests of the ADS valves are discussed in HNP-1-FSAR subsection 4.4.8 and HNP-2-FSAR subsection 5.2.2.

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

6.3.2.17.2 Pump Functional Tests

A pressure-operated control valve, such as the one upstream of the HPCI system gland-seal condenser, is functionally tested and adjusted in place in accordance with the valve manufacturer's manual and the system specification for pressure setting. A test pressure connection is provided to check and adjust the setting.

Flow-operated check valves for reverse flow or excess flow are tested periodically in place by isolating that portion of the system and simulating the function conditions either with the system pump or through test connections provided for this purpose.

Proper position of manual valves for the accident mode is indicated by flow and pressure instrumentation during periodic system tests and after maintenance.

Test lines between pairs of ECCS containment isolation valves measure leakage when the containment is pressurized for tests. The test line is also used to pressurize between the closed valves to identify the leaking valve.

The portions of the ECCS requiring pressure integrity are designed to specifications for inservice inspection to detect defects that might affect cooling performance.[(4)] The RPV nozzles, and CS and feedwater spargers receive particular attention. Records are kept of the number of design basis thermal cycles the components receive.

A. HPCI System

A design flow functional test of the HPCI system up to the normally closed pump discharge valve is performed during normal plant operation by pumping water from the CST and back through the full-flow test return line to the reservoir. Steam from the reactor drives the HPCI system turbine pump at its rated output. Suction valves from the suppression pool and discharge valves to the reactor feedwater line remain closed during the test. The HPCI system is declared inoperable while in the test mode.

HPCI system test conditions are tabulated on the HPCI system process flow diagram (HNP-1 drawing no. S-16122 and HNP-2 drawing no. S-25176). If an initiation signal occurs while the HPCI system is being tested, the system returns to the automatic startup mode and supplies water to the reactor.

The HPCI system may be tested at full flow with condensate at any time except when the RPV water level is low, condensate level in the CST is below the reserve level, and/or valves from the suppression pool to the pump are open.

To test the pump discharge valve, the pump is stopped and the maintenance block valve is closed between the pump and the discharge valve. The discharge valve is then operated with the remote control switch while the valve position lights are being observed.

B. CS System

Each loop of the CS system may be tested during reactor operation. The test conditions are tabulated on the CS system process flow diagram (HNP-1 drawing no. S-15177 and HNP-2 drawing no. S-25178).

The CS pumps are tested at rated flow. The pumps are started using the remote-manual switches in the MCR, and the flow test valve to the suppression

pool is opened. Proper operation is determined by observing the instruments in the MCR. The CS system outside the drywell is checked for leaks.

The two motor-operated injection valves are tested by alternately closing one, cycling the other, and observing the position indicator lights. The test ends with the inboard valve closed (nearer the drywell) and the outboard valve opened.

The CS system injection check valve inside the drywell is tested in accordance with the Inservice Testing Program at a frequency approved by the NRC.

If an initiation signal occurs during the test, the CS system is signaled to start, and the system returns to the automatic mode.

C. LPCI Mode of RHR

The LPCI pumps and valves are tested in accordance with the Inservice Testing Program. With the injection valves closed and the return line open to the suppression pool, full-flow pumping capability is demonstrated. The injection check valves are tested as described previously for the CS valves, and the motor- operated injection valves are tested separately. LPCI test conditions during reactor shutdown are shown on the RHR system process flow diagrams (HNP-1 drawing nos. S-15304 and S-15305, and HNP-2 drawing nos. S-25140 and S-25141). The portion of LPCI outside the drywell is inspected for leaks during the tests. Controls and instrumentation are tested as described in subsection 7.3.1.

Upon receipt of a LPCI initiation signal during the tests, the valves in the test bypass lines and in the shutdown cooling system are closed automatically to ensure the LPCI pump discharge is routed properly to the RPV.

Specifications for ECCS component testing are contained in the HNP-1 and HNP-2 Technical Specifications.

6.3.3 PERFORMANCE EVALUATION (HNP-1 AND HNP-2)

The performance of the ECCS for mitigation of a design basis LOCA is applicable to HNP-1 and HNP-2 unless stated otherwise. This section provides the results of the ECCS LOCA evaluation performed using the SAFER/GESTR-LOCA (GE14 fuel) and SAFER/PRIME (GNF2 fuel) evaluation methods documented in references 2, 5, 14, and 15. The analysis for the power level of 2763 MWt is documented in references 1, 3, 6, and 16. The analysis is based on Appendix K power level of 2818.3 MWt and applies to TPO (2804 MWt) and ROPI to 1060 psia.[7, 8]

More specifically, the ECCS LOCA evaluation documented in reference 1 determines the limiting single failure, discussed in paragraph 6.3.3.3 and contains the break spectrum calculations discussed in paragraph 6.3.3.5. The ECCS LOCA evaluation documented in reference 6 supplements reference 1 and provides ECCS performance results related to 10x10

GE14 fuel. The ECCS LOCA evaluation documented in Reference 16 provides ECCS performance results related to 10x10 GNF2 fuel. Reference 10 provides the evaluation of the impact on ECCS performance of the installation of adjustable speed drives (ASD) to provide power to the recirculation pump motors. The ASDs replace the recirculation pump motor-generator (M-G) sets. With ASDs the coastdown of recirculation pump flow due to the recirculation pump trips following the LOCA is faster since coastdown is controlled only by recirculation pump inertia. This faster coastdown results in an increase of +40 ºF for licensing basis peak-cladding temperature.

6.3.3.1 Acceptance Criteria for ECCS Performance

The acceptance criteria for LOCA accident analyses documented in 10 CFR 50.46 are listed below. Compliance with these criteria is discussed in paragraph 6.3.3.2.

1. Peak-Cladding Temperature (PCT): The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. Maximum Cladding Oxidation: The calculated total local oxidation of the cladding shall not exceed 0.17 times the total cladding thickness before oxidation.

3. Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value, and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

6. ECCS initiation is completely automatic. No operator action is required for at least 10 min following initiation of a postulated accident.

6.3.3.2 Conclusions

Compliance with the criteria provided in paragraph 6.3.3.1 is documented in references 1, 3, 6, 10, and 16. A summary of this compliance is provided in table 6.3-1. The most limiting exposure-dependent maximum average planar linear heat generation rate (MAPLHGR) used in the analysis and the exposure-dependent LHGR resulting from the fuel thermal-mechanical analysis are the operating limits placed in the ***Core Operating Limits Report (incorporated by reference into the FSAR)***. The exposure-dependent MAPLHGR and LHGR limits for each fuel design are provided in the reports listed in table 15.1-1.

6.3.3.3 Single-Failure Considerations

One requirement of 10 CFR 50, Appendix K, is that the worst single failure of ECCS equipment must be assumed to occur during a postulated LOCA. This assumption affects the remaining systems assumed to operate during the calculated LOCA scenario. The single-failure assessment is documented in reference 1 and summarized in table 6.3-2. Consistent with the generic evaluation documented in reference 2, the limiting single failure for HNP-1 and HNP-2 is a dedicated diesel battery failure with the largest recirculation suction line break.

6.3.3.4 LOCA Analysis Procedures and Input Variables

A list of the significant input parameters is presented in tables 6.3-3 and 6.3-4. Table 6.3-3 shows the plant operating conditions and the fuel parameters utilized in the LOCA evaluation. Table 6.3-4 identifies the ECCS parameters utilized for the analyses. These values are analytical limits and may be more conservative than the values specified in the Technical Specifications to maximize LOCA PCT.

All LOCA analyses were performed with a bounding maximum average planar linear heat generation rate (MAPLHGR) at the most limiting power and exposure combination. The most limiting power/exposure combination was determined by performing generic sensitivity studies for each fuel type along the peak power/exposure envelope used for the fuel thermal mechanical design.

The detailed procedures used for the LOCA analyses are documented in reference 2. The results of the single-failure assessment are given in paragraph 6.3.3.3. A summary of the set of computer codes used in these analyses is given below.

<u>Short-Term Thermal-Hydraulic Model (LAMB)</u>

The first analysis is performed with the LAMB computer code used to analyze the short-term blowdown phenomena for large postulated pipe breaks in jet pump reactors. A large break is one in which nucleate boiling is lost before the core water level drops and uncovers the active fuel. The LAMB output of core flow as a function of time is input to the TASC code for the calculation of the blowdown heat transfer and fuel dryout time.

<u>Transient Critical Power Model (TASC)</u>

This code completes the transient short-term thermal-hydraulic calculation for large breaks in jet pump reactors. A boiling transition correlation is used to predict the time and location of boiling transition during the period that the recirculation pumps are coasting down. When the core inlet flow is low, TASC uses a dryout correlation to predict the resulting time and location of bundle dryout. The calculated fuel dryout time is input into the long-term thermal-hydraulic transient model, SAFER.

Thermal-Mechanical Model (GESTR-LOCA or PRIME)

These codes are used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. They also establish the transient pellet-cladding gap conductance for input to both SAFER and TASC.

Long-Term Thermal-Hydraulic Model (SAFER)

This code is used to calculate the long-term response of the reactor over a complete spectrum of hypothetical break sizes and locations. SAFER is compatible with both the GESTR-LOCA and PRIME fuel rod models for gap conductance and fission gas release. SAFER is used to determine, as a function of time, the core water level, system pressure response, ECCS performance, and other primary thermal-hydraulic phenomena occurring in the reactor. SAFER realistically models all regimes of heat transfer that occur inside the core during the event and provides, as a function of time, the heat transfer coefficients and PCT.

6.3.3.5 Break Spectrum Calculations

As documented in reference 1, several break sizes with potentially limiting single failures were analyzed using nominal assumptions and the inputs discussed in paragraph 6.3.3.4. This analysis establishes the shape of the PCT versus break area curve (break spectrum) to ensure the limiting combination of break size, location, and single failure is identified and is the same as the combination determined in the generic evaluation. The trend of PCT with break size is consistent with the trend observed in the BWR 3/4 generic break spectrum. This analysis also demonstrates that the largest possible break in the recirculation suction line with a coincident dedicated diesel battery failure, the limiting single failure as discussed in paragraph 6.3.3.3, results in the highest PCT for the plant and bounds other suction line breaks.

For BWR 3/4 class plants, the generic Appendix K PCT versus the break-size curve exhibits the same trends as the generic nominal PCT versus the break-size curve, and the limiting LOCA determined from the nominal PCT/break spectrum analysis is the same as the limiting LOCA determined from the Appendix K evaluations. The plant-specific licensing basis calculations also match the trend of the generic Appendix K versus the break-size curve.

6.3.3.6 Alternate Operating Modes

The impact on the HNP MAPLHGR limits due to operation in single recirculation loop operation with ARTS, with MELLLA, and with increased core flow and final feedwater temperature

reduction is documented in section 5.3 of Reference 1, in Reference 3, in section 5.4 of Reference 6, and in section 5.4 of Reference 16.

6.3.3.7 LOCA Analysis Peak-Cladding Temperatures

The LOCA licensing methodology includes a calculation of the following three PCTs:

1. Nominal PCT (PCT_{nom}) - directly calculated using nominal input data.

2. Appendix K PCT ($PCT_{App\ K}$) - directly calculated using conservative 10 CFR 50 Appendix K specified models and input data.

3. Licensing basis PCT - The ($PCT_{licensing}$) is based upon the most limiting LOCA event in the analyzed break spectrum, and is calculated from a statistical combination of data uncertainties, calculated PCT_{nom} and calculated $PCT_{App\ K}$. To satisfy 10 CFR 50.46 requirements, $PCT_{licensing}$ must be < 2200°F. The licensing basis PCT will always be greater than or equal to the appendix K PCT.

A summary of the limiting LOCA analysis results for the nominal PCT and Licensing basis PCT is shown in table 6.3-5. The PCT results meet all the acceptance criteria. Changes to the PCT subsequent to the ECCS-LOCA evaluation are shown in table 6.3-6.

6.3.3.8 ECCS Suction Line Analysis (HNP-1 and HNP-2)

The two CS, four RHR, HPCI, and RCIC suction lines have remote-manual MOVs.

A. HNP-1

The lines postulated to rupture are assigned a design rating of 125 psig and 225°F. The maximum anticipated service conditions are 68 psig and 225°F. The calculated stresses in these lines are well below the code allowable stresses for the various loading categories. For example, in an RHR suction line, the calculated total primary stress (pressure, weight, and seismic for the DBE) is 7750 psi versus an allowable stress of 27,700 psi. The calculated secondary stress (thermal expansion) is 10,334 psi versus an allowable stress of 26,250 psi. These lines are designed to Seismic Category 1 and USAS B31.7, Nuclear Piping Class II Requirements, and all welds require a 100% radiographic, magnetic particle, or liquid penetrant examination; therefore, the postulation of a rupture of an ECCS suction line seems unwarranted.

B. HNP-2

The piping, which is classified as ASME Code, Section III, Class 2, was stress analyzed for thermal and deadweight flexibility and seismic dynamic response. This analysis established nozzle loads on the torus connections which, in turn, are analyzed in accordance with ASME Section III-B. As these connections are

situated below the torus, they are protected against possible missiles originating from the slab above the torus or any high-pressure lines situated above the torus.

In the event of unforeseen accidents, suppression pool water will empty into the basement and establish a water elevation of ~ 102 ft msl. The suction connections are at an elevation of 90 ft msl above the basement floor and will, therefore, remain submerged.

The maximum distance between the containment nozzle and the centerline of the isolation valve occurs on the four 24-in. RHR suction lines. The distance is ~ 60 ft.

Piping sections and components that are normally water filled and isolated by boundary valves were reviewed to determine the need for overpressure protection from thermal expansion of contained fluids. The review indicates the ECCS is not subject to fluid thermal expansion due to convective and/or conductive heat transfer to the fluids, since the potential heat sources (i.e., reactor building atmosphere, primary containment atmosphere, and connected systems) are either sufficiently insulated from the pipe section or the heat source is incapable of adding heat to the system.

Specifically, in the case of valves F042 and F041 and the bounded pipe section in the HPCI system, the isolated piping section is physically located entirely within the HPCI pump room. The fluid in this piping section is nonflowing and is normally at or very near the ambient temperature in the HPCI room, thus eliminating the reactor building atmosphere as a potential source of heat addition. Periodic exercising of these valves verifies that no pressure buildup due to thermal expansion of the contained fluids has occurred. Valve F041 is the interface valve between the isolated pipe section and the pump normal suction piping. Since the CST serves as the normal suction source, and in view of the fact the CST is normally operated at a fluid temperature equal to or slightly less than HPCI room ambient temperature, the fluid flowing intermittently through the HPCI pump suction is not a heat source. Valve F042 is the interface valve between the isolated pipe section and suppression pool suction piping. The piping run between the suppression pool and valve F042 is ~ 40 ft long and uninsulated. Even in the unlikely event of a LOCA in which suppression pool temperatures may exceed ambient temperatures by as much as 100°F, the heat loss to ambient will be sufficient to protect the piping system from overpressurization.

In the case of piping bounded by LPCI valves F016A&B, and F021A&B, the piping section is at or very near the ambient temperature of the reactor building. Valves F021 A and B serve as containment isolation valves and are the interface boundary valves between the isolated pipe section and the primary containment spray headers.

The air-filled piping between valve F021A&B, and the containment shell is a minimum of 7 ft long and uninsulated. Heat transferred to this piping is lost to

ambient heating and is not a source of heat sufficient to result in overpressurization of the isolated pipe section. Between valve F016A&B, and the intermittently flowing LPCI pump discharge piping is a run of stagnant, nonflowing liquid piping ~ 30 ft long. Heat conduction and convection along the 30-ft pipe run negate the potential for heat addition to the isolated piping section.

In each ECCS subsystem's isolated piping sections reviewed for overpressure protection requirements, the results of the review were similar to those delineated above. Moreover, each essential valve in the ECCS is subjected to periodic exercising in accordance with the inservice inspection program, and the results of valve surveillance on HNP-1 reveal that, where isolation valves have bounded a piping section filled with water, no hydraulic lock has developed.

C. HNP-1 and HNP-2

In postulating a leak or break in an ECCS suction line in the torus chamber room, the plant is assumed to be in a normal operating condition, and no other accident or AOO is considered.

Leakage detection sumps capable of detecting leakage at a rate of 12 gal/min or greater are located in each quadrant of the torus chamber room, and annunciation of leak detection sump alarms is provided in the MCR. To ensure leakage information from leak detection sump alarms is meaningful, the torus chamber room floor is designed to slope toward the sump for each room quadrant. Additionally, leakage from the torus may be identified by monitoring the suppression pool water level instrumentation.

To identify the leaking or broken ECCS suction line, upon receipt of a leak detection pump alarm, the operator must monitor suppression pool water level, and if the level is observed to be decreasing, isolate the ECCS suction lines in the associated room quadrant, allow the sump to drain to a level where the alarm resets, and methodically reopen the ECCS suction lines while monitoring the leak detection sump alarm. The actuation of the leak detection sump alarm during conduct of this procedure identifies the leaking or broken ECCS suction line, which may be reisolated, and the remainder of the ECCS suction lines may be returned to a normal valve lineup configuration.

In the event the leakage rate from the postulated leaking or broken ECCS suction line exceeds the drain capacity of one sump, additional sump alarms may be expected to annunciate, possibly in rapid succession. Should the operator be unable to determine the quadrant in which the first sump alarm was actuated, isolation of all ECCS suction lines in either the north or south half (thus ensuring isolation of only half the ECCS at any time) of the torus chamber room may be initiated. If this action stops the suppression pool water level decrease, a procedure of reopening the isolation valves similar to that described above is initiated until the leaking or broken line is identified. In the event the isolation of

all ECCS suction lines in half the torus chamber room does not halt the decreasing suppression pool water level, the operator reopens the shut valves and shuts the valves in the remaining half of the torus chamber room.

These leak detection procedures are not sensitive to transient changes in the suppression pool water level. This sensitivity of the described system allows isolation of a leak prior to the leak causing a significant loss of suppression pool water inventory.

The leakage detection system sumps for the torus compartment, HPCI, RCIC, RHR, and CRD equipment rooms are all interconnected. All sumps are equipped with level alarms and a system of remotely operated valves to prevent flooding of compartments other than the one in which a leak occurs.

Post-LOCA ECCS leakage collects in the reactor building floor drain sumps as shown on drawing nos. H-26076 and H-26096. One sump is located in the southwest corner room and the other in the southeast corner room.

Leakage collected in the sumps is pumped to the radwaste system for storage and processing. Should the sump pumps be inoperable, the sumps have sufficient storage capacity available to accommodate the expected ECCS leakage. The minimum storage capacity available in a sump is ~ 950 gal. The storage capacity represents the volume between the sump-level setting for sump pump starting and the high- level setting that initiates closure of valves in the drain lines from the instrument sumps located in each corner room, each quadrant of the torus chamber room, and the HPCI room.

The sources of ECCS leakage considered are the ECCS pumps' mechanical seals. All ECCS pumps have mechanical seals of identical design. The seals have practically immeasurable leakage, with a rate up to ~ 15 cc/h considered normal. Under normal plant conditions, seal leakage 1 1/2 gal/min necessitates a seal replacement. The leak rate for complete failure of a seal is estimated to be 5 gal/min.

For long-term core cooling, either two LPCI pumps, or one CS pump and one LPCI pump are adequate. Should excessive seal leakage or seal failure occur, sufficient redundancy allows the leaking pump to be removed from service and isolated. Four RHR pumps and two CS pumps are provided.

In the unlikely event a sump becomes full during post-LOCA ECCS operation, the leakage is allowed to accumulate on the floor of the compartment in which the leakage occurs. As noted, high sump level initiates drain line valve closures to isolate the corner rooms, torus chamber room, and HPCI room from each other. Essential components that can be affected by flooding are located at a sufficient height above the floor so that an accumulation of a large volume of leakage in the compartment would not affect their proper operation.

All post-LOCA ECCS leakage is into the reactor building. Thus, the SGTS filters all fission product releases as described in subsection 6.2.4.

6.3.3.9 Net Positive Suction Head Analysis (HNP-1 and HNP-2)

A. HNP-1 Short-Term Response

For short-term operation (< 10 min following LOCA initiation), the RHR and CS pumps are assumed to be at runout conditions. The operators make no attempt to throttle the pumps; therefore, the RHR and CS pumps run at the highest flowrate that piping friction losses and RPV pressure physically allow.

- For RHR, runout flow is assumed to be 10,600 gal/min.
- For CS, runout flow is assumed to be 5900 gal/min.
- The reactor is assumed to be at 0 psig.
- The calculated maximum suppression pool temperature is 156°F (Unit 1) 155°F (Unit 2).

The available NPSH (NPSHA) was calculated using the equation:

$$\text{NPSHA} = \frac{(P_1 - P_{SAT})144}{\rho} + Z - (h_{L_{PIPING}}) - (h_{L_{STRAINER}})$$

where:

P_1 = atmospheric pressure (psia).

P_{SAT} = saturation pressure at suppression pool temperature (psia).

ρ = density of suppression pool water (lb/ft^3).

Z = static head (ft).

$h_{L_{PIPING}}$ = piping friction losses.

$h_{L_{STRAINER}}$ = strainer head loss.

Calculations performed at 156°F (Unit 1) 155°F (Unit 2) suppression pool temperature at a power level of 2804 MWt and reactor operating pressure of 1060 psia demonstrate that containment overpressure is not required for either the RHR or CS pumps during the short-term post-LOCA period.

B. HNP-2 Short-Term Response

The LPCI mode of RHR and the CS system are designed to ensure adequate NPSH margin availability under all combinations of foreseeable adverse conditions. The point of minimum margin for all pumps occurs at the peak suppression pool temperature calculated on the basis of conservative assumptions. No dependence is placed on positive containment pressure. The regulatory position given in Regulatory Guide 1.1 (November 1970) is met.

C. HNP-1 and HNP-2 Long-Term Response Analysis Assumptions and Initial Conditions

Analysis assumptions and initial conditions were chosen to minimize calculated containment pressure and maximize calculated suppression pool temperature. The conditions assumed for calculating the available NPSH margin are as follows:

1. The reactor is operating at 2818 MWt, which is 100.5% of the rated thermal power (RTP) of 2804 MWt.

2. The core decay heat is based upon ANSI/ANS 5.1-1979 with 2 σ uncertainty adders. Inputs for enrichment, exposure, and residence time bound the core design for operation at 2804 MWt.

3. Heat sinks are used for the short-term analysis to minimize the chamber airspace pressure. Condensation heat transfer is assumed at all times, unless the structural temperature is greater than the airspace saturation temperature in which case natural convection heat transfer is used. Heat sinks are not used for the long-term analysis to maximize the suppression pool temperature. Heat transfer from the primary containment to the reactor building is conservatively neglected.

4. Feedwater flow into the RPV continues until all hot feedwater (water that contributes to suppression pool heatup) is injected into the RPV.

5. To maximize the calculated suppression pool temperature, the initial suppression pool temperature is at the maximum Technical Specifications value of 100°F, the RHRSW system temperature remains at the maximum allowable value of 97°F throughout the event, and the initial suppression pool volume is at the minimum Technical Specifications limit. The initial suppression chamber airspace temperature is 100°F with an initial relative humidity of 100%.

6. To minimize the initial noncondensible gas mass and the long-term containment pressure for the NPSH evaluation, the initial drywell temperature is 150°F and the initial relative humidity is 100%.

7. The initial drywell and suppression chamber airspace pressures are 14.7 psia.

8. All CS and RHR system pumps have 100% of their horsepower rating converted to a pump heat input that is added to either the RPV liquid or the suppression pool water.

9. The RHR heat exchanger is activated at 600 s into the event.

10. The RHR flowrate is assumed to be 7700 gal/min and CS flowrate is 4725 gal/min.

11. Thermodynamic equilibrium exists between the liquids and gases in the drywell. Mechanistic heat and mass transfer between the suppression pool and the suppression chamber airspace are modeled to minimize suppression chamber airspace pressure and temperature. Heat transfer from break fluids to the drywell atmosphere is adjusted to minimize suppression chamber airspace pressure.

12. The vent system flow to the suppression chamber consists of a homogeneous mixture of the fluid in the drywell.

13. Containment leakage at the Technical Specifications limit of 1.2%/day is assumed in the calculation of containment pressure response.

14. The drywell and suppression chamber sprays are assumed to have 100% thermal mixing efficiency between the spray liquid, and the drywell and suppression chamber atmospheres.

D. HNP-1 Long-Term Response

The original RHR and CS pump suction strainers were replaced with larger-capacity strainers. The new strainers are large enough that adequate NPSH is available at all pump operating conditions, with all the debris assumed to reach the suppression pool, coating the strainers.

Using the results of the long-term analysis and the preceding equation (item A above) for available NPSH, it was determined that 2.91 psig (6.7 ft) of containment overpressure is required to ensure adequate NPSH to the RHR pumps, and 2.85 psig (6.6 ft) of containment overpressure is required to ensure adequate NPSH to the CS pumps at the peak calculated suppression pool temperature of 210ºF.

Using the calculated suppression pool temperature profile, containment overpressure is required for a period from ~2.6 h to 18.7 h after LOCA initiation. To provide sufficient margin for the peak suppression pool temperature of 210°F, the long-term NPSH evaluation takes credit for a containment overpressure of 4.2 psig (10 ft). The overpressure credit is applied for a period of 1.5 to 26.5 h

following LOCA initiation.[2] Any changes resulting in an individual or collective increase of 1 ft (~ 0.4 psig) of the containment overpressure margin of 10 ft (4.2 psig) requires NRC notification. Plots of the long-term NPSH calculation results for the RHR and CS pumps are shown in figures 6.3-5 and 6.3-6, respectively.

E. HNP-2 Long-Term Response

The long-term containment response analysis demonstrates the RHR and CS pumps have NPSH margin without taking credit for containment overpressure.

6.3.3.10 ECCS Pump Suction Strainers Analysis (HNP-1 and HNP-2)

Due to concerns regarding potential clogging of the original pump suction strainers by fibrous debris loosened during a LOCA, the RHR and CS strainers were replaced with larger-capacity strainers. General Electric (GE) supplied a high-performance stacked-disk strainer design that had been full-scale tested. The hydraulic loss information was based upon proprietary test data obtained from testing a structurally qualified and fabricated strainer.

In sizing the RHR and CS suction strainers, GE was provided debris loading equivalent to a scenario calculated in accordance with Section C.2.2 of Regulatory Guide 1.82, Rev. 2, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident." This is as specified in Option 1 of NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," May 6, 1996. The Boiling Water Reactor Owners' Group (BWROG) Utility Resolution Guidance for ECCS Suction Strainer Blockage was used to determine the amount and types of debris assumed to reach the strainers following a large-break DBA LOCA. The debris included NUKON® fibrous insulation, foil from reflective metal insulation (RMI), dust, dirt, coatings, suppression pool sludge (corrosion products), and miscellaneous maintenance debris (wood chips, duct tape, tie wraps). To provide some degree of conservatism and assure the future adequacy of the new strainer size, the amount of debris provided to GE for the sizing calculations was somewhat larger than the amount actually calculated.. As an additional conservatism, the maximum head loss allowed for the strainer(s) was reduced by ~ 2 ft from the calculated allowable. The strainers were sized to filter the specified debris while maintaining the RHR and CS pumps NPSH margin greater than zero at all times, consistent with the peak suppression pool temperature calculated for TPO and ROPI.

The Unit 1 RHR and CS suction lines have two strainers each, the Unit 2 RHR suction lines have two strainers each, and each Unit 2 CS suction line has one strainer. The strainers are a stacked-disk type and are constructed of SA 240 Type 304 stainless steel, except for the ribs, which are constructed of SA 412 XM19 stainless steel. The steel support pipe on top of the strainer is SA 312 Type 304 stainless steel. The perforated plate through which water passes is 11-gauge stainless steel with 1/8-in. diameter holes in a 3/16-in. triangular pitch (33 holes/in^2).

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

HNP-1 and HNP-2 Core Operating Limits Reports (located in the HNP-1 and HNP-2 Technical Requirements Manuals, Appendix A).

REFERENCES

1. "Edwin I. Hatch Nuclear Power Plant, SAFER/GESTR-LOCA, Loss-of-Coolant Accident Analysis," <u>NEDC-32720-P</u>, General Electric Company, March 1997.

2. "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," <u>NEDC-23785PA</u>, Revision 1, General Electric Company, October 1984.

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

4. Brandt, F. A., "Design Provisions for In-Service Inspection," <u>APED-5450</u>, General Electric Company, April 1967.

5. "GESTR-LOCA and SAFER Models for Evaluation of Loss-of-Coolant Accident, Volume III, Supplement 1, Additional Information for Upper Bound PCT Calculation," NEDE-23785P-A, Revision 1, General Electric Company, March 2002.

6. "Hatch Units 1 and 2 ECCS-LOCA Evaluation for GE14," <u>GE-NE-0000-0000-9200-02P</u>, General Electric Company, March 2002.

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

8. “10-PSI Dome Pressure Increase Project Report for Edwin I. Hatch Units 1 and 2,” <u>GE-NE-0000-0003-0634-01</u>, Revision 1, GE Nuclear Energy, July 2003.

9. GEH 0000-0126-6532-R1, Revision 1, “Ultimate Heat Sink Temperature Increase to 97ºF Impact on DBA-LOCA Analysis and DW Equipment Qualification Analysis,” June 2011.

10. “Edwin I. Hatch Nuclear Plants, Units 1 & 2 Adjustable Speed Drives Implementation Project – Transient and LOCA Support,” 0000-0055-5361-R0, Revision 0, GE Hitachi Nuclear Energy, October 2008.

11. Deleted

12. Letter from M. J. Ajluni to USNRC (NL-11-1652), “Edwin I. Hatch Nuclear Plant 10 CFR 50.46 ECCS Evaluation Model Significant Change/Error Report,” dated August 12, 2011.

13. NEDC-32938P-A, Revision 2, “Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization,” (TLTR), May 2003.

14. GNF Licensing Topical Report, “The PRIME Model for Analysis of Fuel Rod Thermal-Mechanical Performance,” September 2010:
    - Technical Bases - NEDC-33256P-A, Revision 1
    - Qualification - NEDC-33257P-A, Revision 1
    - Application Methodology - NEDC-33258P-A, Revison1

15. NEDO-33173, Supplement 4-A, Revision 1, GEH Licensing Topical Report, “Implementation of PRIME Models and Data in Downstream Methods,” September 2011.

16. GEH Report 000N8505-R0, “Edwin I. Hatch Nuclear Plant GNF2 ECCS-LOCA Evaluation,” December 2014.

17. Letter from C. R. Pierce to USNRC (NL-13-2576), “Edwin I. Hatch Nuclear Plant Units 1 and 2; Vogtle Electrical Generating Plant Units 1 and 2; 10 CFR 50.46 ECCS Evaluation Model Annual Report for 2012,” dated December 23, 2013.

18. Letter from C. R. Pierce to USNRC (NL-14-0900), “Edwin I. Hatch Nuclear Plant Units 1 and 2 10 CFR 50.46 ECCS Evaluation Model Annual Report for 2013 and Significant Change/Error Report,” dated June 20, 2014.

19. Letter from C. R. Pierce to USNRC (NL-15-0680), “Edwin I. Hatch Nuclear Plant Units 1 and 2 10 CFR 50.46 ECCS Evaluation Model Annual Report for 2014 and Significant Change/Error Report,” dated April 8, 2015.

TABLE 6.3-1

ECCS PERFORMANCE RESULTS
(HNP-1 AND HNP-2)

	Analysis for Operation at 2763 MWt RTP[b,c]		
Criterion	GNF2 (10x10)	GE14 (10X10)	Limit
Licensing basis PCT[a] (°F)	2110	1930	≤ 2200
Cladding oxidation (%) original cladding thickness	< 6.0	< 2.0	≤ 17
Hydrogen generation (core-wide metal-water reaction) (%)	< 0.1	< 0.1	≤ 1.0
Coolable geometry	OK	OK	Meet 1 and 2 above
Core long- term cooling	OK	OK	Core remains covered to jet pump elevation, and one low-pressure loop operates.

a. Licensing basis PCT differs slightly from the Appendix K PCT, as described in reference 2. Limiting PCTs are provided and have been corrected where applicable for vendor error notifications.
b. The current 10 CFR 50, Appendix K LOCA analyses were performed at 2818 MWt and vessel steam dome pressure of 1073 psia and remain bounding.
c. The thermal power optimization (TPO) report (Reference 7) justifies reducing the instrumentation uncertainty from 2.0% to 0.5%. With this justification, the HNP is approved to operate at 101.5% of the licensed thermal power: 2,804MWt = 101.5% of 2,763 MWt. The TPO core thermal power remains bounded by the current Appendix K ECCS-LOCA analysis power level, consistent with the generic TPO LTR (Reference 13). The LOCA basis nominal power is therefore 2,763 MWt and maintains the LOCA licensing basis for TPO operation.

TABLE 6.3-2

SINGLE-FAILURE ASSESSMENT[a]
(HNP-1 AND HNP-2)

Assumed Failure[b]	Recirculation Suction Line Systems Remaining[c]	Recirculation Discharge Line Systems Remaining
Station Service Battery	2CS+2LPCI+ADS[d][e]	2CS+ADS
Diesel Battery		
Swing DG 1B	2CS+1LPCI+HPCI+ADS	2CS+HPCI+ADS
Dedicated DG	1CS+2LPI2+HPCI+ADS	1CS+1LPCI+HPCI+ADS
HNP-1 (1A or 1C)		
HNP-2 (2A or 2C)		
LPCI Injection Valve (LPCI IV)	2CS+2LPCI+HPCI+ADS	2CS+HPCI+ADS
Diesel Generator (DG)		
Swing DG 1B	2CS+1LPCI+HPCI+ADS	2CS+HPCI+ADS
Dedicated DG	1CS+3LPI2+HPCI+ADS	1CS+1LPCI+HPCI+ADS
HNP-1 (1A or 1C)		
HNP-2 (2A or 2C)		

a. The single failure shown in this table reflects the most limiting set of single failures based upon the configuration of the plant.

1LPCI - One LPCI pump injects into one recirculation loop.
2LPCI - Two LPCI pumps inject into one recirculation loop.
2LPI2 - Two LPCI pumps inject into two recirculation loops.
3LPI2 - Three LPCI pumps inject into two recirculation loops.

b. Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures. Note that the systems remaining for the diesel battery failure bound all other possible single failures.

c. Systems remaining for the recirculation suction break are applicable to all non-ECCS line breaks. For an ECCS line break, the systems remaining are those listed for the recirculation suction break, less the ECCS train in which the break is assumed.

d. No credit is taken for HPCI in this evaluation.

e. All LOCA analyses are performed assuming two ADS valves are unavailable to conservatively bound the scenario of an ADS valve out of service and a single failure of another ADS valve.

TABLE 6.3-3 (SHEET 1 OF 2)

OPERATIONAL PARAMETERS FOR LOCA ANALYSES[b]
(HNP-1 AND HNP-2)

Parameter	GE14 (10x10) [a] Nominal	Appendix K
Core thermal power (MWt)	2763	2818.3
Corresponding power (%)	100.0	102.0
Core flow (lb/h)	77.0M	77.0M
RPV steam dome pressure (psia)	1060	1073
Maximum recirculation suction line break area (ft^2)	4.14	4.14
Feedwater Temperature (°F)	397.5	399.5

a. Parameters have been selected to bound HNP-1 and HNP-2.
b. There is a small change to the operational parameters used as input to the current ECCS analyses (GE-NE-0000-0000-9200-02P, March 2002). However, as stated in reference 8, there is no significant impact on the results of the current analyses due to reactor operating pressure increase to 1060 psia. The operational parameters have not been revised since the values provided in this table were used for the actual analyses.

TABLE 6.3-3 (SHEET 2 OF 2)

OPERATIONAL PARAMETERS FOR LOCA ANALYSES (HNP-1 AND HNP-2)

Parameter	GNF2 (10x10)[a] Nominal	Appendix K
Core thermal power (MWt)	2763	2818.3
Corresponding power (%)[b]	98.5	100.5
Core flow (lb/h)	77.0M	77.0M
RPV steam dome pressure (psia)	1060	1073
Maximum recirculation suction line break area (ft^2)	4.163	4.163
Feedwater Temperature (°F)	391.0	393.0

a. Parameters have been selected to bound HNP-1 and HNP-2.
b. The thermal power optimization (TPO) report (Reference 7) justified reducing the instrumentation uncertainty from 2.0% to 0.5%. With this justification, HNP is approved to operate at 101.5% of the licensed thermal power: 2,804MWt = 101.5% of 2,763 MWt. The TPO core thermal power remains bounded by the current Appendix K ECCS-LOCA analysis power level, consistent with the generic TPO LTR (Reference 13). The LOCA basis nominal power is therefore 2,763 MWt and maintains the LOCA licensing basis for TPO operation.

TABLE 6.3-5

SUMMARY OF LOCA ANALYSIS RESULTS
(HNP-1 AND HNP-2)

-Break Size -Model Assumptions -Location -Single Failure	PCT(°F)*	Peak Local Cladding Oxidation (%)	Core-Wide Metal-Water Reaction (%)
	GE14 (10x10)		
DBA Nominal Recirculation suction line break Dedicated diesel battery failure	1150	-	-
DBA Licensing basis Recirculation suction line break Dedicated diesel battery failure	1860	< 2.0	< 0.10
	GNF2 (10x10)		
DBA Nominal Recirculation suction line break Dedicated diesel battery failure	1327	-	-
DBA Licensing basis Recirculation suction line break Dedicated diesel battery failure	2110	< 6.0	<0.10

*Value based off original ECCS-LOCA analysis for GE14 fuel performed in 2002 (rebaselined for adjustable speed drive implementation), and for GNF2 fuel performed in 2014. This value is only updated when a completed LOCA reanalysis is performed and is not updated when an error or change is identified which affects the LOCA model calculated PCT.

TABLE 6.3-4 (SHEET 2 OF 4)

System/Mode	
HPCI[h] (continued)	
Maximum allowable time delay from initiating signal to rated flow available and injection valve wide open	75 s
ADS	
Total no. of valves installed	7
No. of valves assumed in analysis [i]	5
Minimum flow capacity of any 5 valves	3.94×10^6 lbm/h
Pressure at which ADS capacity is quoted	1080 psig
Initiating signals:	
Low-low-low water level	TAF [b]
and	
High drywell pressure	2.0 psig
Time delay after initiating signals	130 s
or	
Low-low-low water level	TAF[b]
and	
Bypass timer	13 min

a. Parameters have been selected to bound HNP-1 and HNP-2.
b. Top of active fuel (358 in. above vessel zero).
c. No credit is taken for high drywell pressure initiation signal in Appendix K analysis.
d. Full LPCI or CS flow is assumed to be achieved prior to the valve being full open. The full-stroke time justified by the analysis is reported.
e. Pressure permissive assumed conservatively low.
f. 4250 gal/min at 113 psid is reduced in the analysis by 100 gal/min to reflect slip joint leakage and by an additional 150 gal/min to account for any other leakage outside the shroud.
g. 5300 gal/min at 0 psid is reduced by 250 gal/min for slip joint leakage and other leakage outside the shroud. The original CS sparger design flow used for long-term cooling (core spray flow distribution) was 4625 gal/min.
h. Credit is not taken for HPCI in the LOCA analysis.
i. Two ADS valves are assumed unavailable to conservatively bound the scenario of an ADS valve out of service and a single failure of another ADS valve.
j. Power to these valves is assumed to coincide with the 21-s emergency diesel generator startup time.

TABLE 6.3-4 (SHEET 3 OF 4)

PLANT ECCS PARAMETERS [GE14 (10x10)][a]
(HNP-1 AND HNP-2)

System/Mode	
LPCI Mode of RHR	
RPV pressure at which flow may commence	207 psid
Minimum rated flow for:	
2 pumps into 1 loop	14,850 gal/min
2 pumps into 2 loops	16,490 gal/min
Initiating signals and setpoints	
Low-low-low water level	L1[b]
or	
High drywell pressure	2.0 psig[C]
Maximum allowable time delay from initiating signal to pump at rated speed	64 s
RPV pressure at which LPCI injection valve can open	380 psia
Injection valve stroke time [i]	46 s[d]
Recirculation discharge (DSCG) valve:	
Pressure permissive for closure	150 psia[e]
DSCG valve stroke time [j]	43 s
Core Spray	
RPV pressure at which flow may commence	284 psid
Minimum rated flow for 1 loop	4250 gal/min[f]
Initiating signals and setpoints:	
Low-low-low water level	L1[b]
or	
High drywell pressure	2.0 psig[c]
Maximum allowed (runout) flow	5300 gal/min[g]
Maximum allowable delay time from initiating signal to pump at rated speed	10 s
Injection valve stroke time[j]	15 s[d]
RPV pressure at which CS low-pressure injection valve can open	380 psia
HPCI[h]	
RPV pressure at which flow may commence	1210 psia
Minimum rated flow for RPV pressure range of 1210 to 165 psia	4250 gal/min
Initiating signals and setpoints:	
Low-low water level	L2[b]
or	
High drywell pressure	2.0 psig[c]

TABLE 6.3-4 (SHEET 4 OF 4)

System/Mode	
HPCI[h] (continued)	
Maximum allowable time delay from initiating signal to rated flow available and injection valve wide open	75 s
ADS	
Total no. of valves installed	7
No. of valves assumed in analysis[i]	5
Minimum flow capacity of any 5 valves	3.94×10^6 lbm/h
Pressure at which ADS capacity is quoted	1080 psig
Initiating signals:	
Low-low-low water level	L1[b]
and	
High drywell pressure	2.0 psig
Time delay after initiating signals	120 s
or	
Low-low-low water level	L1[b]
and	
Bypass timer	13 min

a. Parameters have been selected to bound HNP-1 and HNP-2.
b. L1 (low-low-low) Level Setpoint is 364.5 in. above vessel zero (VZ); top of active fuel is 358.56 in. above VZ. L2 (low-low) Level Setpoint is 459 in. above VZ.
c. For the GNF2-based analysis, credit is taken for high drywell pressure initiation signal for both Nominal and Appendix K analysis.
d. Full LPCI or CS flow is assumed to be achieved at 50% of full-open stroke time. The full-flow stroke time listed supports a full-open strike up to two times this value.
e. Pressure permissive assumed conservatively low.
f. 4250 gal/min at 113 psid is reduced in the analysis by 100 gal/min to reflect slip joint leakage and by an additional 150 gal/min to account for any other leakage outside the shroud.
g. 5300 gal/min at 0 psid is reduced by 250 gal/min for slip joint leakage and other leakage outside the shroud.
h. Credit is not taken for HPCI in the LOCA analysis.
i. Two ADS valves are assumed unavailable to conservatively bound the scenario of an ADS valve out of service and a single failure of another ADS valve.
j. Power to these valves is assumed to coincide with the 21-s emergency diesel generator startup time.

TABLE 6.3-5

SUMMARY OF LOCA ANALYSIS RESULTS
(HNP-1 AND HNP-2)

-Break Size -Model Assumptions -Location -Single Failure	PCT(°F)*	Peak Local Cladding Oxidation (%)	Core-Wide Metal-Water Reaction (%)
	GE14 (10x10)		
DBA Nominal Recirculation suction line break Dedicated diesel battery failure	1150	-	-
DBA Licensing basis Recirculation suction line break Dedicated diesel battery failure	1860	< 2.0	< 0.10
	GNF2 (10x10)		
DBA Nominal Recirculation suction line break Dedicated diesel battery failure	1327	-	-
DBA Licensing basis Recirculation suction line break Dedicated diesel battery failure	2110	< 6.0	<0.10

*Value based off original ECCS-LOCA analysis for GE14 fuel performed in 2002 (rebaselined for adjustable speed drive implementation), and for GNF2 fuel performed in 2014. This value is only updated when a completed LOCA reanalysis is performed and is not updated when an error or change is identified which affects the LOCA model calculated PCT.

TABLE 6.3-6

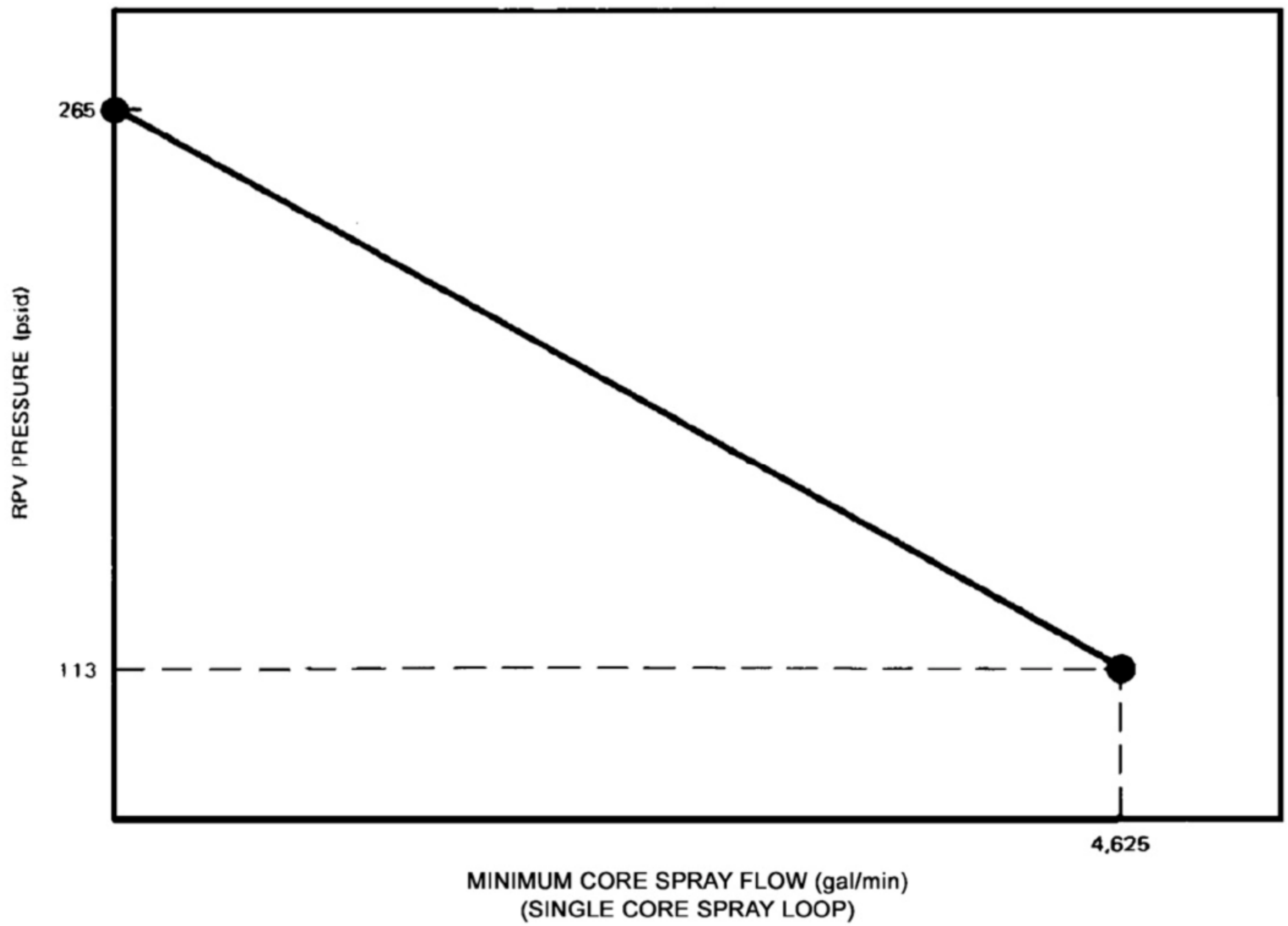
SUMMARY OF LICENSING BASIS PCT RESULTS (HNP-1 AND HNP-2)

GE14 Fuel

Licensing Basis PCT from ECCS-LOCA Evaluation for GE14	1820 ºF	Reference 6
PCT change from installation of adjustable speed drives, established a revised Licensing Basis PCT of 1860 ºF (includes errors up through 2008-01)	+40 ºF	Reference 10
PCT change from error in input coefficients used to direct the deposition of gamma radiation energy produced by fuel	+45 ºF	Reference 12
PCT change from error regarding contribution of heat from gamma ray absorption by the channel	+ 5 ºF	Reference 12
PCT change from PRIME code implementation for fuel rod T/M performance, replacing GESTR	+ 10 ºF	Reference 17
PCT cumulative change from SAFER04A E4 Revision	+ 10 ºF	Reference 18
Total corrected Licensing Basis PCT	1930 ºF	

GNF2 Fuel

Licensing Basis PCT from ECCS-LOCA Evaluation for GNF2 (includes errors up through 2014-04)	2110 ºF	Reference 16, 19



ACAD 2060301

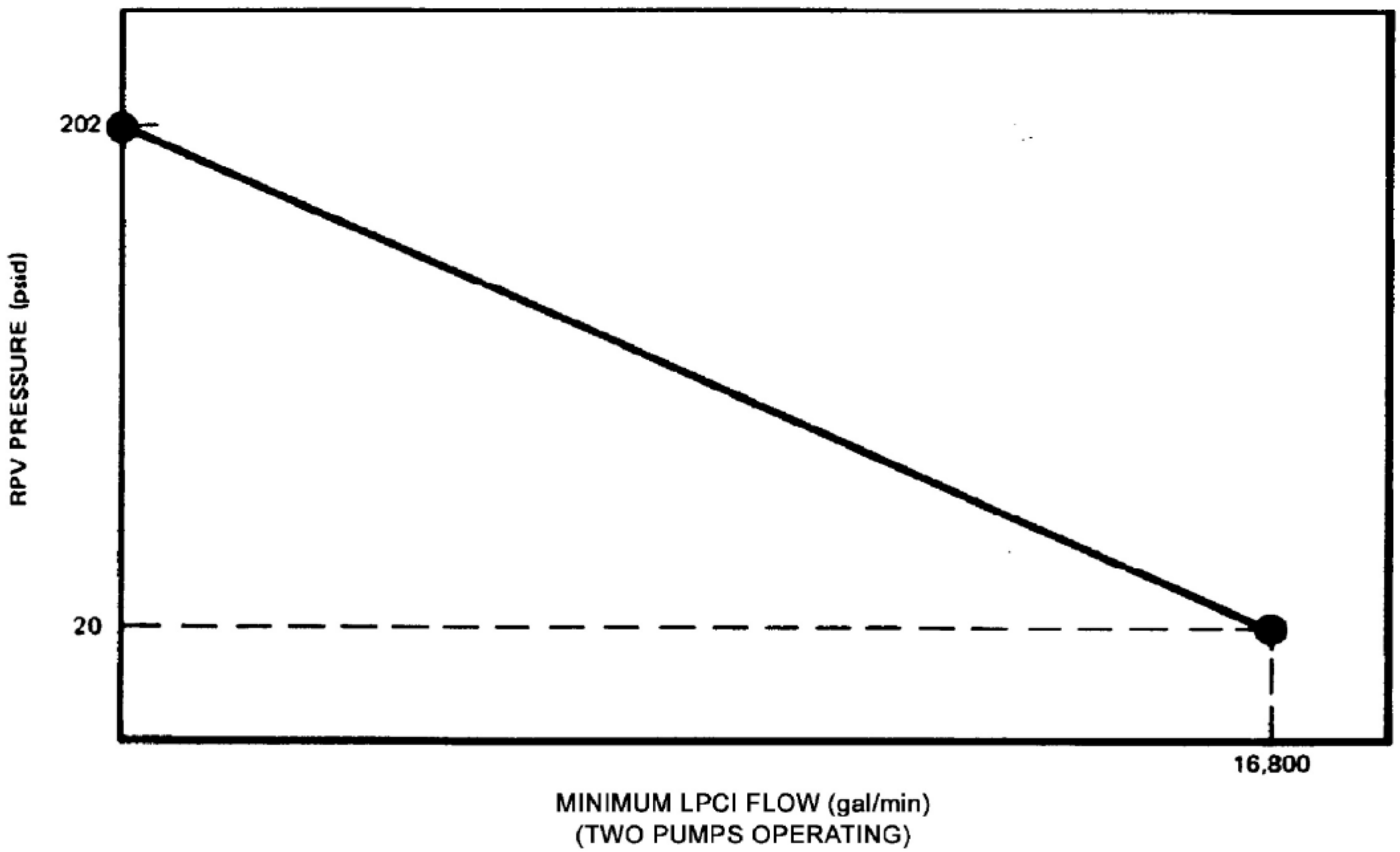
REV 21 7/03

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CS SYSTEM PERFORMANCE CURVE

FIGURE 6.3-1



ACAD 2060302

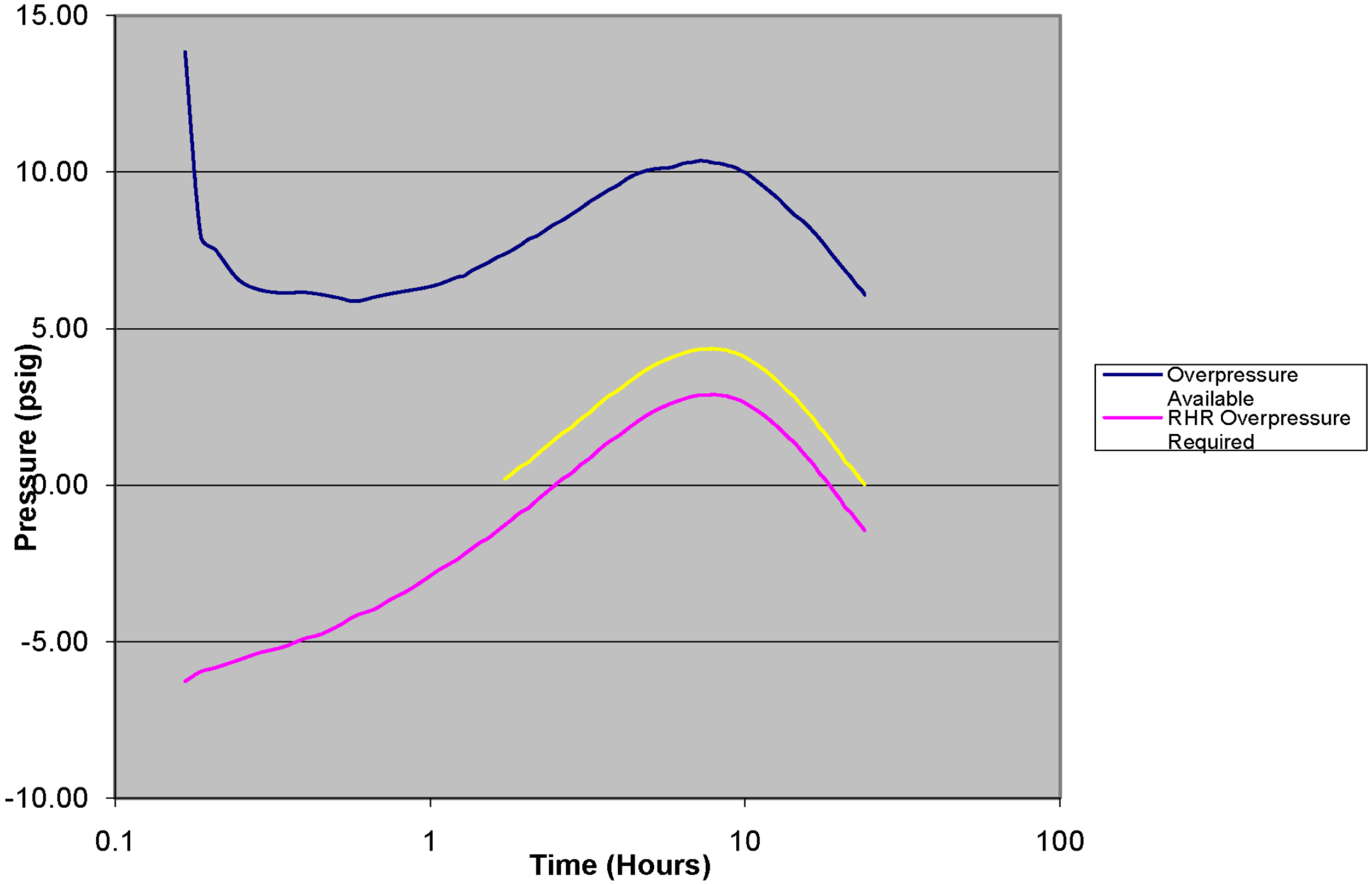
REV 21 7/03

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LPCI PERFORMANCE CURVE

FIGURE 6.3-2



ACAD 1060502

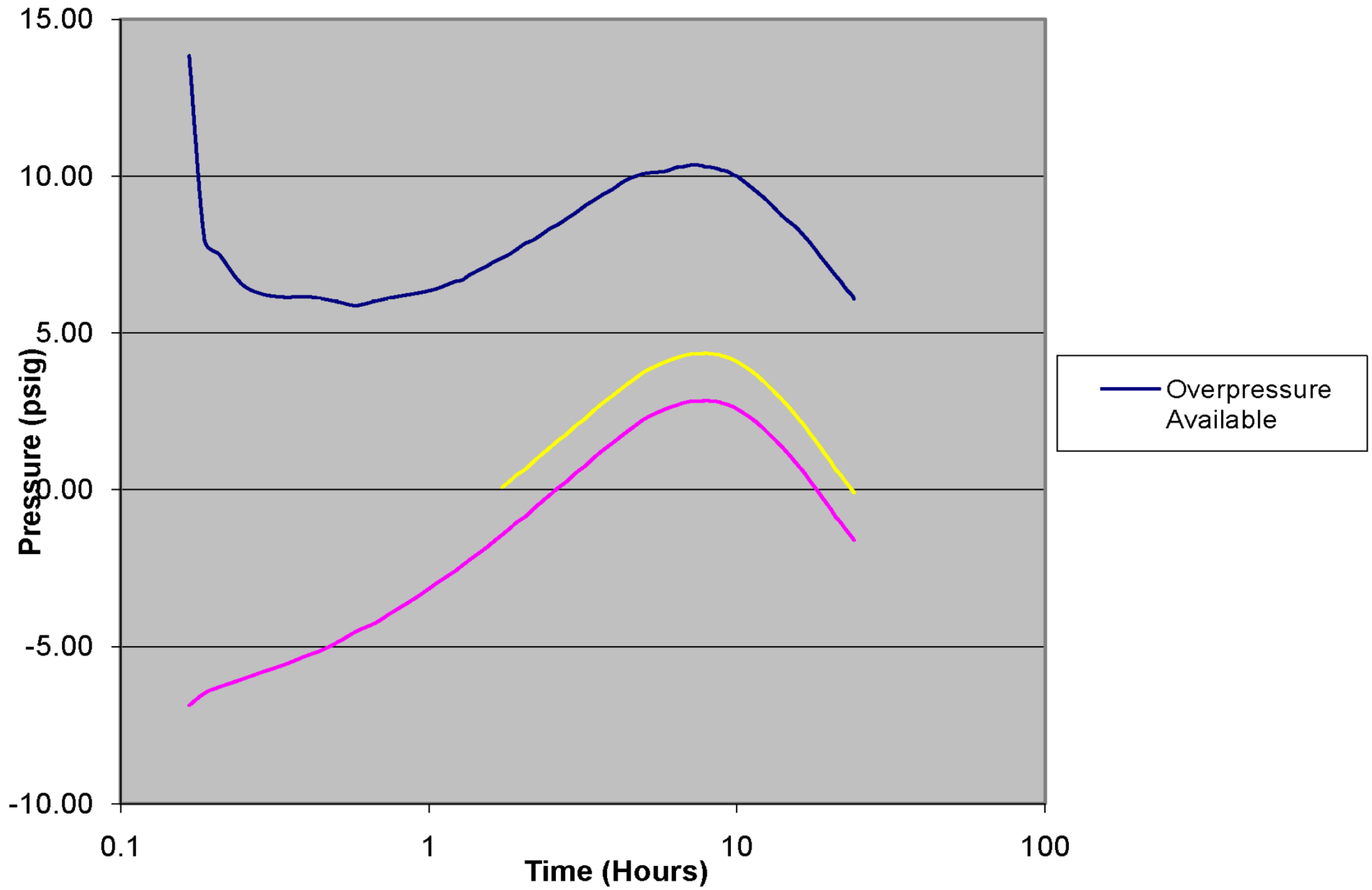
REV 30 9/12

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RHR PUMP NPSH EVALUATION

FIGURE 6.3-5



ACAD 1060503

REV 30 9/12

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CS PUMP NPSH EVALUATION

FIGURE 6.3-6

6.4 HABITABILITY SYSTEMS (HNP-1 AND HNP-2)

The habitability systems described in this section are applicable to HNP-1 and HNP-2 unless specified otherwise.

6.4.1 HABITABILITY SYSTEMS FUNCTIONAL DESIGN

The heating, ventilation, and air-conditioning (HVAC) system is shared by HNP-1 and HNP-2.

The main control room (MCR) habitability systems are designed to provide safety and comfort for operating personnel during normal operations and postulated accident conditions. The habitability systems for the MCR include radiation shielding, charcoal and other filter systems, HVAC, sanitary facilities, and fire protection.

A discussion of the MCR systems that control the climatic conditions existing within the MCR is found in HNP-1-FSAR paragraph 10.9.3.6 and HNP-2-FSAR subsection 9.4.1. Shielding considerations are discussed in chapter 12. MCR habitability is discussed in section 15.4.

The MCR habitability systems are designed to meet Nuclear Regulatory Commission (NRC) General Design Criterion (GDC) 19, which is discussed in HNP-1-FSAR section F.3 and HNP-2-FSAR section 3.1.

6.4.1.1 Safety Design Bases

A. The postulated accident conditions are defined and the extent of simultaneous occurrences is discussed in chapter 15. The radiological parameters influencing habitability are the products of release found in the atmosphere surrounding the MCR.

B. The assumptions regarding the sources and amounts of radioactivity surrounding the MCR are discussed in section 15.3.

C. The pressurization mode of operation of the MCR environmental control (MCREC) system minimizes the amount of radioactivity entering the MCR following an accident. The MCR atmosphere is recirculated through the MCREC system emergency filters with sufficient outside air being drawn in through the normal intake to maintain the MCR at a positive pressure of ≥ 0.1-in. water gauge (WG) relative to the surrounding turbine building.

D. Following a postulated DBA, the limitations of MCR temperature, humidity, and radioactivity concentrations are as follows:

Parameter	Design
MCR temperature	≤ 79ºF
MCR humidity	≤ 75%
Radioactivity concentrations	Appendix A, 10 CFR 50

E. Noncombustible materials are used in construction and equipment as much as possible. The quantity of combustible material, such as paper and other flammable supplies, is kept to a minimum. Plant operators receive training in firefighting; therefore, a trained firefighter is on duty at all times.

Fire protection for the MCR is discussed in HNP-1-FSAR section 10.8 and HNP-2-FSAR subsection 9.5.1. Fire protection for the MCREC system charcoal adsorbers is discussed in paragraph 6.4.1.4.

F. Sanitary facilities are available within the boundary of the MCR habitability systems.

G. Although closely related to the type I description in paragraph C.3.a of Regulatory Guide (RG) 1.95, the HNP-1 and HNP-2 MCR is not in complete agreement, because it does not comply with the entire description of any of the listed control room types.

Since no gaseous chlorine is used or stored on site, the need to consider a chlorine accident is not warranted.

H. No pressurization test as described in paragraph C.5 of RG 1.95 is currently scheduled. This test is not necessary, since gaseous chlorine is neither used nor stored on site.

6.4.1.2 System Description

The MCREC system is shown schematically on drawing no. H-16042. Major system components and significant parameters associated with each component are listed in tables 6.4-1 and 9.4-1. The HNP-1 and HNP-2 MCRs are housed in a shared facility as shown on drawing no. H-16249. The habitability systems are designed to service the HNP-1 and HNP-2 combined MCRs.

The MCREC system supplies HVAC for the MCR, which is common for HNP-1 and HNP-2. The principal equipment in the system includes:

- Three 50% capacity air-handling units (AHUs) with cooling coils and fans. Two of the AHUs contain operational electric heaters in the associated MCR supply ductwork.

- Three 50% capacity condensing units, each consisting of refrigerant compressor, condenser, and associated controls that service the AHU cooling coils. Plant service water provides cooling water for the condensing units.

- Two 100% capacity exhaust air fans.

- Two trains of high-efficiency air filtration units consisting of a prefilter, a high-efficiency particulate air (HEPA) filter, an electric carbon drying heater, a carbon adsorber, a second HEPA filter for emergency treatment of recirculated air or outside supply air, and two filtration unit booster fans (one for each filtration unit).

6.4.1.2.1 Normal Operation

During normal operation, the room air is recirculated through each operating AHU. A ducted air supply provides fresh makeup air that is filtered during normal operation by a roll filter and mixed with the recirculated air before it passes over the cooling coil of each operating AHU. Each of the three return air paths from the MCR is provided with prefilters. The electric heaters can heat the supply air to the MCR in accordance with room temperature requirements for personnel comfort. HNP-1-FSAR subsection 10.9.3 and HNP-2-FSAR subsection 9.4.1 provide additional discussion of system operation.

A portion of the airflow through the AHUs is makeup from outside air so that the MCR is normally maintained at a slightly positive pressure relative to the surrounding turbine building. The outside makeup air passes through a dust filter before reaching the suction of the AHU fans.

The MCREC system is designed to automatically pressurize the MCR in the unlikely event of high-radiation detection in the supply duct to the AHUs. In the event of high-radiation detection, all normal outside air supply and exhaust dampers are closed, and outside air and a part of the recirculated air are routed through either of the two filter trains. This filtered air is mixed with the recirculated air and supplied to the MCR through the AHU.

The filtration units in the MCREC system have prefilters, a charcoal adsorber bed, and HEPA filters. Each prefilter is rated at 1000 ft^3/min and is designed for 85% to 90% efficiency in accordance with American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard, 52-76. The charcoal adsorber is mounted in a dual-tray module drawer to provide a 2-in. adsorber bed thickness. Each tray has a nominal air flow rating of 333 ft^3/min. Each drawer contains ~ 45 lb of activated charcoal with an expected methyl iodide removal efficiency (tested) of 97.5%. Each HEPA filter is rated for 1000 ft^3/min and maximum total dioctyl phthalate (DOP) smoke penetration of 0.05% of upstream concentration with 0.3-μm aerosols. Paragraph 6.4.1.2.2.2 discusses the pressurization mode sequence of events.

6.4.1.2.2 Accident Condition Operation

The MCR HVAC system is designed to ensure habitability following any of the following design basis accidents (DBAs):

- LOCA.
- Fuel-handling accident.
- Main steam line break accident (MSLBA).
- Control rod drop accident (CRDA).

These DBAs are discussed in detail in section 15.3. The accident mode operates as described below.

6.4.1.2.2.1 Pressurization Mode. The pressurization mode of operation is intended to protect MCR operators in the event of a DBA. Operating AHU(s) will remain in service, and if needed, the standby AHU will autostart to ensure at least one AHU remains in service to assist the positive pressurization of the MCR.

The following parameters are monitored to provide an initiating signal to the MCREC system to establish the pressurization mode:

- LOCA signal from HNP-1 or HNP-2.
- Refueling floor high radiation from HNP-1 or HNP-2.
- Main steam line high flow from HNP-1 or HNP-2.
- MCR air intake high radiation.

Upon receipt of any one of the above initiating signals, the following automatic functions occur (drawing no. H-16042):

A. Series redundant isolation dampers F011 and F012 close to prevent outside air from bypassing the charcoal filters.

B. Outside air isolation damper F015 opens to provide a parallel source of pressurization air from outside.

C. MCR restrooms exhaust dampers F019 and F020 close.

NOTE: The restroom dampers do not have redundant and independent isolation capability. However, the restroom doors, which are normally closed, act as the redundant barrier between the MCR and the outside

in the event the damper fails to close. Following initiation of the pressurization mode, the exhaust dampers are confirmed closed, and the restrooms are considered accessible through the doors.

D. AHU inlet isolation dampers F007A,B,&C, and F008A,B,&C from the MCREC system charcoal filter trains open.

E. MCREC system charcoal filter recirculation inlet isolation damper F014A opens for fan C012A or damper F014B opens for fan C012B, whichever fan starts.

F. If operating, MCR exhaust fan C011A or B is stopped, and the associated isolation damper F018A or B is closed.

NOTE: The isolation dampers are not redundant; thus, the exhaust fans are normally not operated, and the isolation dampers are normally closed.

G. MCREC system charcoal filter outside air inlet isolation dampers F013A&B open.

H. Booster fans C012A&B for charcoal filter trains D004A&B start to establish filtered recirculation of the MCR environment and also pressurization of the MCR with filtered outside air. Following verification of proper fan and exhaust damper operation, operators can shut off one booster fan.

I. The cable spreading room supply and exhaust fans are secured to preclude a potential malfunction of those fans which could potentially impact the capability to maintain the MCR at a positive pressure relative to the surrounding turbine building. Following automatic trip of the cable spreading room supply and exhaust fans, the fans are confirmed tripped.

The MCR is now positively pressurized $\geq$ 0.1-in. WG relative to the surrounding turbine building. Approximately 400 ft^3/min of outside air taken in at the normal ventilation intake on the west wall of the control building is mixed with ~ 2100 ft^3/min of MCR air and passed through the charcoal adsorber filter train for removal of airborne radioactivity. The normal AHUs continue to recirculate air at ~ 14,000 ft^3/min/operating AHU. When the MCR ventilation system is operating in the pressurization mode, entrance and exit from the MCR are only through the double doors (airlock) shown on drawing no. H-16249.

6.4.1.2.2.2 **Other Modes.** To limit the temperature rise in the MCR during a station blackout event, "egg crate" ceiling tiles are installed in the MCR to permit natural circulation between the MCR proper and the area above the tiles.

6.4.1.3 Instrumentation Application

Differential pressure indicators are provided locally to measure the pressure drop across each filter element. The overall pressure drop across each filter train is measured and alarmed in the MCR on high ΔP.

Each charcoal adsorber is provided with at least two temperature switches, any one of which can actuate an alarm in the MCR when the filter temperature rises above a preset value. The electric carbon drying heating coils in the filter trains are controlled by a temperature control set at 85°F. These heaters automatically shut down when the associated filter train booster fan starts.

In the pressurization mode of operation, outside air is mixed with recirculated air. Even under conditions of high outside humidity, the air mixture entering the charcoal adsorber will be < 70% relative humidity, without humidity controls.

Radiation monitors are provided in the outside air intake duct and in the MCR. The monitors alarm in the MCR upon detection of high-radiation conditions.

Redundant ΔP switches sense the ΔP between the MCR and the turbine building. These switches alarm in the MCR on low ΔP when the MCREC system is in the pressurization mode.

The instrumentation used to provide the initiating signals for MCR pressurization is discussed in HNP-1- and HNP-2-FSAR subsections 7.2.2 and 7.3.2, and HNP-1-FSAR section 7.12 and HNP-2-FSAR subsection 7.6.3.

6.4.1.4 Safety Evaluation

The shielding in the MCR is discussed in HNP-1-FSAR and HNP-2-FSAR chapter 12. The shielding is designed for continuous occupancy during a LOCA and meets GDC 19.

The MCREC system is designed with sufficient redundancy and separation of active components to provide reliable operation under normal conditions and ensure operation under emergency conditions. Where redundancy does not exist (e.g., restroom exhaust dampers and exhaust fan isolation dampers), the system is normally operated so that at least one isolation barrier is normally closed. In the case of the restrooms, the doors provide that barrier. Upon verification that the exhaust dampers have closed for the pressurization mode, access to the restrooms is allowed via these doors. In the case of the exhaust fan isolation dampers, the fans are normally not operated, and the dampers are normally closed.

Combined, the MCR habitability systems provide maximum safety and comfort for operating personnel during normal and postulated accident conditions. A failure analysis of MCREC system components is shown on table 6.4-2.

Double doors for the MCR allow ingress/egress under emergency conditions (drawing no. H-16249). If, under emergency conditions, the air temperature near the carbon adsorber bed reaches 200°F, the heat detection system initiates an alarm in the MCR. The carbon drying

system is then deactivated and will require manual resetting. The fan is also deactivated, and the associated dampers are closed, thus isolating the filter. The deluge system is manually activated as needed. When conditions permit, the water spray may be manually secured.

Radiological and toxicological consequences of DBAs are described in detail in chapter 15.

The MCR return air prefilters are classified as nonsafety related.

6.4.1.5 Tests and Inspections

Normal operational surveillance of the habitability systems is in accordance with the HNP-1 and the HNP-2 Technical Specifications. Periodic inplace testing of the HEPA filters and the charcoal adsorbers verifies no excessive bypass leakage exists. The HVAC system operates during normal conditions and does not require special operation for testing.

Testing the filter units satisfies the inplace testing and acceptance criteria and uses the test procedures detailed in Regulatory Positions C.5.a, C.5.c, and C.5.d of RG 1.52, Revision 2, March 1978, and ASME N510-1989. Sampling and testing of carbon samples are accomplished in accordance with Regulatory Position C.6.b of RG 1.52, Revision 2, March 1978. Inplace testing procedures conform to applicable sections of ASME N510-1989. Carbon samples are tested for methyl iodide removal efficiency in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%.

Regulatory Guide 1.52, Revision 2 recommends an 18-month surveillance interval for ventilation filter testing. It states that certain factors, including “industrial contaminants, pollutants, temperature, and relative humidity contribute to the aging and weathering of filters and adsorbers, and reduce their capability to perform their intended functions.” Periodic testing is specified as a means of ensuring reliability of these components. The 18-month surveillance interval was specifically recommended in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in Table 2, which is associated with Sections C.6.a and C.6.b. The regulatory guide does not discuss any specific failure mechanisms or degradation factors that were the basis for specifying 18 months. ASME N510-1989 specifies a recommended frequency of once per operating cycle, with no specific time value given for an operating cycle. Therefore, the 18-month surveillance interval recommendation within Regulatory Guide 1.52 is interpreted as once per operating cycle.

During HNP-2 startup testing, the MCR ventilation system was tested to verify that, upon an initiation test signal, the system automatically switches into the pressurization mode of operation and maintains the MCR at ≥ 0.1-in. WG pressure relative to the adjacent turbine building. This test is performed periodically in accordance with the Technical Specifications. In addition, each MCR air-conditioning subsystem is tested periodically to verify its capability to remove the assumed heat load.

TABLE 6.4-1 (SHEET 1 OF 2)

MCREC SYSTEM COMPONENT DESCRIPTION
(HNP-1 AND HNP-2)

Filter Trains	
No.	2
Size, each (% capacity)	100
Type	Multiple filters for removal of particulates, elemental iodine, organic iodine, and bromine from air
Capacity, each (sf^3/min)	2500
Charcoal Adsorbers (Each Train)	
No.	1 bank
Type	2-in. tray
Capacity (sf^3/min)	2500
Media	Activated charcoal
Methyl iodide removal efficiency (%) tested	97.5 (minimum)
Relative humidity (%)	95 (maximum)
Residence time (s)	0.25 (minimum)
Ignition temperature range (°F)	662-752
Iodine desorption temperature range (°F)	250-300
Charcoal iodine loading (30-day accident duration)	2.5-mg (maximum) iodine per g activated charcoal
Pressure drop (in. WG)	0.8
Particle size distribution (mesh)	12 x 20 (per ASTM 2862 test method)
HEPA Filters (Each Train)	
No.	2 banks
Type	High-efficiency dry
Capacity (sf^3/min)	2500
Media	Glass fiber
Efficiency (%)	99.95 with 0.3-μm DOP smoke
Pressure drop, clean (in. WG)	0.6

TABLE 6.4-1 (SHEET 2 OF 2)

Prefilters (Each Train)

No.	1 bank
Type	Dry
Capacity (sf^3/min)	2500
Media	Glass fiber
Efficiency (%)	85 (ASHRAE 52-76)
Pressure drop, clean (in. WG)	0.3

Carbon Drying Heaters (Each Train)

No.	1
Type	Electric
Rating (watts)	526

Booster Fans (Each Train)

No.	1
Size (% capacity)	100
Type	Centrifugal
Capacity (sf^3/min)	2500
Drive	Direct

NOTE:

1. Air-handling units and exhaust air fans are discussed in HNP-1-FSAR subsection 10.9.3 and HNP-2-FSAR subsection 9.4.1.

TABLE 6.4-2

MCREC SYSTEM FAILURE ANALYSIS (HNP-1 AND HNP-2)

Component	Malfunction	Comments
Booster fan	Failure of fan resulting in reduction in airflow	If operating fan fails, resultant reduction of airflow actuates an alarm in the MCR, automatically starts standby booster fan, and opens standby filter train isolation valves.
Electric carbon drying heating coil	Failure of coil control resulting in constant coil operation	Maximum capacity of electric heating coil is not sufficient to cause damage.
	Failure of coil or coil control resulting in no heat	Coil is not essential to filter operation in LOCA emergency recirculation mode.
MCREC system filter train	Failure resulting in high ΔP across filter train	High ΔP across filter train automatically actuates an alarm in the MCR. Defective filter train is manually isolated; standby train is manually placed in service.
Charcoal adsorber	High temperature in charcoal bed	Temperature sensors in each charcoal bed alarm in the MCR upon rising charcoal temperature. Deluge system is manually activated as needed.
Isolation damper	Failure to close or close completely	A series redundant damper provides required isolation.
Operational damper	Failure to open or open completely	A parallel redundant damper provides flow path for required operation.
AHUs and exhaust air fans	All postulated failures	See table 9.4-2.
Cable spreading room fans trip relay	Relay failure	Redundant relay available

SUPPLEMENT 6A

SUBCOMPARTMENT PRESSURIZATION STRUCTURAL ANALYSIS

A dynamic analysis was performed using a lumped-mass, beam-element model for the event of annulus pressurization due to a circumferential break of the recirculation outlet or feedwater lines.

Time-histories of the dynamic reaction at the base of the reactor pressure vessel (RPV) support skirt and the stabilizer springs for each break are presented graphically.

6A.1 INTRODUCTION

In the event of a circumferential break at the safe-end-to-pipe weld of the recirculation line or the feedwater line, a pressure transient can occur in the compartment between the RPV and the reactor shield wall. As the pressure builds up in this annulus region, loads are imposed on the RPV support skirt and the stabilizer springs.

This supplement provides the dynamic reactions at the base of the RPV support skirt and the stabilizer springs that resulted from a dynamic analysis of the structures involved.

For the analysis, loadings on the RPV and the shield wall were generated for the recirculation and feedwater line breaks. Time-histories of these loadings were input into a dynamic model of the system to obtain the dynamics reactions at the points of interest.

6A.2 ANALYSIS

6A.2.1 COMPUTER CODE

The structural analysis and matrix interpretive system (SAMIS) computer code[1] was chosen for the analysis. This code was used successfully for similar analyses on standard boiling water reactor (BWR) 6/238 plants. It is also the only code available that can handle several load functions with different time-histories and considers the effect of hydrodynamic masses in the RPV.

The analysis method used is based upon the SAMIS methods used for seismic response modified to handle force inputs instead of acceleration inputs.[1]

To analyze the response to the recirculation or the feedwater line breaks, time-histories of the forces acting on the structures were input to a lumped mass SAMIS model. SAMIS then calculated acceleration, displacements, and load time-histories using matrix methods.

The output includes a printout of the maximum shear and the moment at selected points.

6A.2.2 DYNAMIC MODEL

The reactor building and drywell, together with the pedestal, shield wall, and RPV, were included in the dynamic model, since it was considered a coupled system.

The dynamic model used in the analysis is a combination of Bechtel's seismic analysis model[2] and the General Electric (GE) RPV mathematical model.[3] The model, as input in the analysis, consists of 95 nodes, 88 beam elements, and 15 springs (figure 6A-1).

The model is two dimensional with the positive X direction pointing towards the center of the RPV.

The east-west direction was chosen for input of section properties of the buildings. It should be noted that the material properties of the reactor building and the drywell are given in terms of concrete, while those for the pedestal, shield wall, and RPV are in terms of steel.

6A.2.3 LOAD INPUTS

The type of dynamic loads associated with a circumferential break of the recirculation and feedwater lines are as follows (figure 6A-2):

- Asymmetrical pressure loads on the RPV and shield wall.
- Jet reaction load on the RPV.
- Jet impingement loads on the shield wall.

- Pipe whip restraint load on the shield wall.

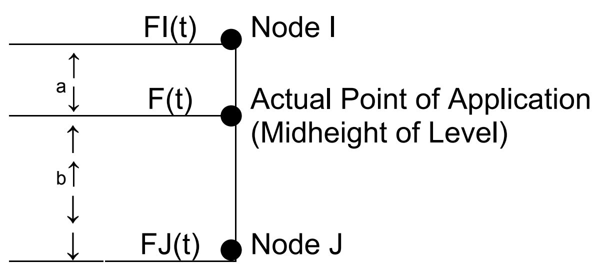
- Acoustic (decompression wave) load on the shroud.

6A.2.3.1 Asymmetrical Pressure Loads

Due to the fluid flow caused by the reactor blowdown, a resultant unbalanced pressure exists in the annulus. Bechtel Corporation evaluated the pressure loads using the COPDA computer code.[4] Time-histories of the pressure loads are shown graphically in figures 6A-3 and 6A-4.

Since the input to SAMIS must be in the form of concentrated loads, the annulus region was divided vertically into six levels. The pressure at each level was converted into a concentrated force that represents the resultant acting at mid-height of the level.

In the dynamic model these loads were applied at the two nodes closest to the actual point of application according to the following procedure:



where:

F(t) = actual load input.

FI(t) = load applied at node I.

FJ(t) = load applied at node J.

$$FI(t) = \frac{F(t) \times b}{a + b}$$

$$FJ(t) = \frac{F(t) \times a}{a + b}$$

6A.2.3.2 Jet Reaction Load on RPV

This load acts at the centerline of the nozzle where the break occurred. For conservatism, the steady-state value was used starting at time zero.

The values used in the analysis are:

$$F = 1.26\ PA^{(5)}$$

where:

F = jet reaction load on RPV.

P = RPV internal pressure (1050 psi).

A = cross-sectional area of nozzle.

For the recirculation outline line:

F = 1.26 x 1050 x 528 = 698,642.0 lb at el 161.5 in.

For the feedwater line:

F = 1.26 x 1050 x 99 = 131,135.0 lb at el 483.5 in.

6A.2.3.3 Pipe Whip Restraint Load

GE generated the pipe whip restraint load for the recirculation outlet line break, and Bechtel generated the pipe whip restraint load for the feedwater line break.(4)

The pipe whip restraint load acts on the shield wall away from the RPV. The time-histories are shown in the following tabulation.

Recirculation Outlet		Feedwater Line	
Time (s)	Restraint Load (lb)	Time (s)	Restraint Load (lb)
0.0	0.0	0.0	0.0
0.0	0.0	0.011	0.0
0.0125	147,791.0	0.012	8400.0
0.015	298,086.0	0.0124	44,600.0
0.0175	438,578.0	0.013	80,300.0
0.02	615,168.0	0.0136	114,500.0
0.0225	692,646.0	0.0142	146,400.0
0.025	736,214.0	0.0148	175,300.0
0.027	747,000.0	0.0154	201,000.0
0.0276	747,000.0	0.016	223,200.0
0.03	747,000.0	0.0166	241,800.0
1.02	747,000.0	0.0172	256,700.0
		0.0178	268,100.0
		0.0184	275,900.0
		0.0190	280,500.0
		0.0196	281,900.0
		0.0196	214,000.0
		1.02	214,000.0

6A.2.3.4 Jet Impingement Loads

Bechtel generated the jet impingement loads on the shield wall for both the recirculation and feedwater line breaks. These loads are applied as the constant loads from time equals zero. The magnitudes of the jet impingement loads are as follows:

- Recirculation outlet, maximum jet force = 446,000.0 lb with center of pressure at el 187.0 in.

- Feedwater line, maximum jet force = 124,000.0 lb with center of pressure at el 498.0 in.

There are no jet impingement loadings on the RPV.(6)

6A.2.3.5 Acoustic Load

A lateral load in the direction of the break is imposed on the shroud as a result of the propagation of the decompression wave created by the sudden recirculation line break. GE generated this load. Time-history of the acoustic load for the recirculation line break is shown in the following tabulation.

Time (m-s)	Acoustic Load (lb)
0.0	0.0
1.2	0.0
1.8	340000.0
2.2	420000.0
2.6	755000.0
2.8	500000.0
3.0	240000.0
3.2	0.0

Acoustic load for the feedwater line break was not considered in the analysis because it is believed to be insignificant. In any case it is much less severe than that caused by the recirculation outlet line break and, as is seen later, the effect of the acoustic load for the recirculation outlet line break is very small as compared to the total effect from all other loads.

6A.2.4 STATIC ANALYSIS

In order to evaluate the results of the dynamic analysis and determine the degree of amplification or reduction of the dynamic reactions, a simplified model of the RPV and shield wall was prepared using the beam and boundary elements of the SAP4GE computer code.

The model consists of 39 nodes, 34 beam elements, and 3 boundary elements. The base of the RPV and of the shield wall were assumed fixed, and the stabilizer spring was modeled by an equivalent stiffness beam element. The model is shown in figure 6A-5.

The loads input into this static analysis were the same as those for the dynamic analysis. Several runs were made to determine the reactions at the base of the RPV support skirt and stabilizer spring for different points in time.

The results of this analysis are plotted together with the dynamic response for comparison purposes (figures 6A-6 through 6A-11).

6A.3 RESULTS

6A.3.1 RECIRCULATION OUTLET LINE BREAK

To perform the required analysis time-histories, all the loadings were input into SAMIS to determine the dynamic reactions of two main points of interest, namely the RPV support skirt base and the stabilizer spring. However, the acoustic load effects were analyzed separately from all other loads because of their smaller time duration (0.002 s).

The results of the structural analysis are presented in this section. The first 30 modes were considered for response, and a time step of 0.004 s was found to be adequate for all the time-histories, with the exception of the acoustic load for which a time interval of 0.0002 s was necessary. The analysis was carried out to 1.02 s.

The dynamic response for shear at the base of the RPV support skirt is shown graphically in figure 6A-6 and maximum values are shown in table 6A-1. As can be seen from figure 6A-6, at time of maximum response, there is a dynamic amplification of ~ 1.26.

Figure 6A-7 shows the dynamic moment at the base of the RPV skirt versus time. Comparison with the static moment shows the dynamic load factor to be close to 1.0 at time of maximum response.

The shear reaction at the stabilizer springs shown in figure 6A-8 is the difference in shear between the two adjacent elements to the stabilizer connection on the RPV; therefore, it represents the force taken by the spring.

Maximum values for the dynamic reactions, shear, and moment at the base of the RPV skirt and the stabilizers spring are shown in table 6A-1. Table 6A-2 shows the effect of the acoustic load at the times of maximum shear or moment reactions due to all other loads. As seen from the table, the effect of the acoustic load is very small, mainly because of its short duration time (td = 0.002 s). Equating this time of duration with the natural period, T, of the shroud, where the load is applied, the dynamic load factor maximum (DLFmax) would be 0.05 if compared to a DLFmax vs td/T curve for a 1-degree system.[7] Therefore, a small dynamic reaction should be expected from this impulse-type loading.

As a mean to check into this reasoning, a simple 2 degrees-of-freedom dynamic model was prepared using the dynamic analysis option of SAP4GE computer code.

6A.3.2 FEEDWATER LINE

Analysis of the feedwater line break was done in the same manner as for the recirculation outlet line. The only changes are in the magnitude of the loads and their points of application.

The results are shown graphically in figures 6A-9 through 6A-11, and maximum values are shown in table 6A-3.

6A.3.3 SUMMARY OF RESULTS

Results show that the recirculation outlet line break has more severe effects on the RPV support skirt than would the feedwater line. However, the load imposed on the stabilizer springs is greater for the feedwater line break.

The recirculation inlet line break was not analyzed, because the loadings for this break are of lesser magnitude than those for the recirculation outlet line break, and both breaks occur at about the same elevation.

Computer Run No.	Case
HSWPS	SAMIS damping run
HAPRS	SAMIS recirculation outlet response run (all loads)
HACLS	SAMIS recirculation outlet (acoustic load run)
HTFDS	SAMIS feedwater line run (all loads)
30305	SAP4GE recirculation outlet static analysis run
30005	SAP4GE feedwater line static analysis run

Model

The dynamic model was prepared using the beam elements of SAP4GE computer code. A boundary element was used at the base to find the dynamic reaction.

The stiffness of each beam element was computed using the mass and natural frequency of the RPV for element 1, and of the shroud for element 2, by means of the relation:

$$w = \sqrt{k/m}$$

where:

w = natural circular frequency

m = mass

k = stiffness

therefore, for element 1:

$$\text{RPV mass} = 6.085 \ \frac{\text{kips - s}^2}{\text{in.}}$$

$$w = 2\pi \ x \ f = 2\pi \ x \ 10.3 = 64.72 \text{ rad/s}$$

$$k = w^2 \ x \ m = 25.5 \ x \ 10^3 \text{ kips / in.}$$

for element 2:

$$\text{shroud mass} = 2.95 \ \frac{\text{kips - s}^2}{\text{in.}}$$

$$w = 2\pi \times f = 2\pi \times 5.9 = 37.1 \text{ rad/s}$$

$$k = w^2 \times m = 4.1 \times 10^3 \text{ kips / in.}$$

The cross-sectional areas of the elements were computed as follows:

$$\text{Area of RPV} = \frac{K1}{E} = \frac{25.5 \ (10)^3 \ (847.75)}{29 \ \times \ 10^3} = 745 \text{ in.}^2$$

where:

1 = 847.75 in. = RPV height

$$\text{Area of shroud} = \frac{L1}{E} = \frac{41(10)^3 \ (485.0)}{29 \ (10)^3} = 66.9 \text{ in.}^2$$

A damping coefficient of 2% of critical was used.

Results

Maximum dynamic reaction at the base of the model was found to be 39.7 kips at time 0.063 s (computer run no. 23635, damping included).

When a run with zero damping was made, the dynamic reaction was larger, but not significantly. For this case, maximum reaction was 45.9 kips at 0.024 s.

Based upon these results, the reasoning offered in section 6A.3.1 regarding the dynamic effects of the acoustic load seems to be justified.

6A.4 SUBCOMPARTMENT PRESSURIZATION ANALYSIS WITHIN SACRIFICIAL SHIELD ANNULUS AND DRYWELL AREA

Results of the subcompartment pressurization analyses due to breaks inside primary containment are presented below. The results include pressure responses within the reactor vessel shield annulus and drywell head region for postulated ruptures of high-energy lines within those regions and ΔPs within the drywell caused by flow around pipes, ducts, and components following a loss-of-coolant accident (LOCA). Further discussion is referenced to NEDO-21576, "Hatch 2 Reactor Pressure Vessel Support Skirt Structural Analysis for Annulus Pressurization," January 1977.

6A.4.1 SACRIFICIAL SHIELD ANNULUS AND DRYWELL HEAD AREAS

Analyses for the vessel shield annulus and drywell head regions regarding the pressure response in these areas from postulated ruptures of high-energy lines were completed. Three breaks in the annulus (recirculation outlet, recirculation inlet, and feedwater) were analyzed, and one break (head spray[a]) in the drywell head region was analyzed. The only other high-energy line located in the annulus is the 10-in. core spray (CS) line. The postulated break area and the blowdown data for the CS line are provided in table 6A-4. The highest absolute pressure obtained for the CS break was 40 psia, which is less than the pressures obtained for the postulated breaks analyzed in this subsection.

Each break analyzed was assumed to be an instantaneous double- ended guillotine rupture which resulted in the maximum flowrate of fluid and maximum release of energy. The break areas assumed for the recirculation outlet, recirculation inlet, feedwater, and head spray[b] line breaks are provided in table 6A-5.

Justification of the break areas assumed for those lines in the annulus and head region is provided in table 6A-5. For the recirculation outlet, recirculation inlet, feedwater, and the head spray[a] lines, the minimum flow area of the safe-end becomes the limiting breakflow area on the vessel side of the break, because the break is defined to occur at the safe-end-to-pipe weld. However, for the recirculation inlet line, the minimum flow area of two jet pumps becomes the limiting break flow area after the blowdown mass has emptied from the break location to the jet pump throat.

The annulus pressurization effect between the RPV and the sacrificial shield wall due to all high-energy line breaks is based upon blowdown mass flow calculations resulting from a full double-ended circumferential break at the pipe junction to vessel nozzle safe end location. The location and break type are selected to satisfy the criteria described in section 3.6. No limit displacement ruptures were considered.

However, as noted in footnote (a) to table 6A-5 and shown in figure 6A-12, the flow into the annulus in the case of the recirculation outlet line break is limited by the clearance between the safe end and the sacrificial shield inservice inspection door. The resultant pressure transients from the pipe breaks postulated were used to reevaluate the compartment structural design and compartment support design. The design of the sacrificial shield inservice inspection door limits the recirculation pipe movement following a break at the safe-end-to-pipe weld. The break areas for the lines provided in table 6A-4 were assumed to be the maximum flow area (inside diameter) resulting from a complete double-ended shear.

Table 6A-5 (Sheet 1 of 2) provides a tabulation of the blowdown mass and energy release rates for the recirculation outlet, recirculation inlet, feedwater, and head spray[a] line break analyses for operation at the original rated conditions of 2436 MWt.

The mass flux values (G) and enthalpy values (h), which are presented in table 6A-4, were determined following a calculational procedure which includes the effects of subcooled liquid blowdown and the effects of the fluid inventory in the broken pipe. The Moody subcooled liquid blowdown model was used to address the effects of the subcooled liquid, and justification for the use of this model is presented below. The pipe inventory blowdown rates were determined based upon the results of the analysis in

---

a. RPV head spray is deactivated; head spray information is maintained for historical purposes.

Appendix B to NEDO-20533. (Note that the analysis in NEDO-20533 was reviewed and accepted by the Nuclear Regulatory Commission (NRC) as part of their review of the GE Standard Safety Analysis Report that was prepared for the BWm R/6 Mark III plants.) Record of this acceptance is documented in the August 14, 1975, letter from Butler to I. F. Stuart.

Based upon the discussion (NEDO-20533) of the rate at which blowdown flow accelerates, it can be concluded the blowdown flowrate has an initial mass flux lower than the mass flux predicted by the Moody critical flow model using the initial fluid conditions in the broken pipe. This flow exists for as long as it takes to deplete the fluid originally in the pipe. Following depletion, the flux corresponds to the Moody flow.

Therefore, the mass flux values (G) presented in table 6A-5 were obtained as follows:

G = 9500 lb /ft^2-s in the G value corresponding to P = 1060 psia and h = 525 Btu/lbm.

G = 4000 lb /ft^2-s for the inventory side of the recirculation inlet break.

This is the mass flux obtained from augmenting the liquid G_M value by a factor of 0.5 to account for the blowdown flow acceleration. G_M in this case is defined at the conditions of P = 1060 psia, and h = 550 Btu/lb and is equal to 8000 lb_m/ft^2 s. The use of this 0.5 value to account for the inventory effort was accepted by the NRC in their review of NEDO-20533. Also, as noted in the discussion below of the 525-Btu/lb enthalpy value, this calculated mass flux value of 4000 lb /ft^2-s is conservative, because the effects of friction and turning losses in the pipe were neglected.

G = 4000 lb_m/ft^2-s for the vessel side of the recirculation inlet break.

This is the mass flux obtained for the inventory period in which the initial conditions of the liquid were: P = 1060 psia, h = 525 Btu/lb_m. For this case, the conservative acceleration factor of 0.5 was not used. Instead, the mass flux during the depletion period was calculated directly, using the methods described in NEDO-20533, and the conservatism was added to the final results. Completing the analysis, as discussed in NEDO 20533, at the aforementioned initial conditions, this inventory period mass flux was calculated to be 3790 lb_m/ft^2-s and was conservatively rounded up to the value of 4000 lb_m/ft^2-s, as presented.

G = 2100 lb_m/ft^2-s is the G_M value corresponding to P = 1060 psia and h = 1190 Btu/lb_m.

G = 2360 lb_m/ft^2-s is the mass flux calculated for the period of inventory depletion of the broken feedwater line back to the junction in the feedwater loop. It is again obtained from 0.5 times G_M. In this case, the pressure in the line is assumed to drop to the saturation pressure corresponding to the temperature of the fluid; i.e. 325 psia, and the G_M value is, therefore, 4720 lb_m/ft^2-s.

G = 6650 lb_m/ft^2-s is the mass flux conservatively calculated for the period in which the remaining fluid inventory in the piping; i.e., in the feedwater loop piping between the junction and the feedwater pump, is expelled. Again, due to the long run of pipe being addressed, the pressure in the line is assumed to drop to the saturation pressure of 325 psia. Although the G_M value corresponding to this pressure of 325 psia and enthalpy of 402 Btu/lb_m is again 4720 lb^m/ft^2-s, the mass flux was modified to the higher value presented so the time required to deplete the fluid inventory in this portion of the

feedwater loop will be reduced. Reducing this period of inventory depletion hastens the time at which the higher flux, higher energy steady-state flow from the vessel; i.e., via the unbroken pipe in the loop, through the pipe junction, and on to the break in the pipe, commences. Note that this particular sequencing of breakflows was compared to the other possible flowpaths that can occur in the feedwater piping, and the flows presented are most conservative.

The enthalpy values (h) presented in table 6A-5 were obtained as follows:

h = 550 Btu/lb_m corresponds to saturated liquid at ~ 1060 psia.

h = 525 Btu/lb_m corresponds to liquid at 1060 psia, which is 25 Btu/lb_m subcooled.

The steady-state blowdown flow was conservatively assumed to be subcooled, because both the mass and the energy flowrates that result are greater than those that result from saturated breakflows. However, note that even though saturated conditions are assumed in determining the mass flux values during some inventory depletion periods, the mass flux values presented are still considered to be conservative assumptions because of other conservative assumptions made, such as the assumptions of the frictionless flow and no turning losses.

h = 1190 Btu/lb corresponds to saturated steam at ~ 1060 psia.

h = 402 Btu/lb corresponds to the enthalpy of the feedwater flow at 105% (rated steam flow) power level.

The calculations performed to determine the appropriate mass flux value were strictly hand calculations and no computer codes were used.

The assumptions made in performing these analyses are as follows:

1. *All postulated breaks occur at the nozzle safe-end-to-pipe weld.*

2. *Fluid inventory and subcooled effects were included whenever appropriate.*

3. *Friction and turning effects in piping were neglected.*

4. *The RPV does not depressurize during the time period addressed in the analyses.*

The time intervals presented in table 6A-5 correspond to the fluid inventory depletion periods (where appropriate) and the subsequent periods of steady-state flow from the breaks. The inventory depletion time (t) is conservatively defined by the relationship:

$$t = \frac{M}{\dot{M}} = \frac{\text{intial fluid mass in pipe}}{\text{mass flowrate during inventory depletion period}}$$

$$= \frac{M}{G \times A} \text{ s}$$

Therefore, using the values of (G) and (A) presented in table 6A-5, the corresponding periods of inventory depletion were calculated.

For the case of the inventory depletion period on the vessel side of the recirculation inlet break, the value of 0.132 s was obtained as follows:

$$t = \frac{M}{G \times A}$$

where:

M = initial fluid mass in the inlet riser pipe in the region between the break and the jet pump nozzles.

$$t = \frac{383.4}{(4000)\ (0.723)} = 0.132 \text{ s}$$

Figures 6A-13, 6A-14, 6A-15, and 6A-16 provide, in graphic form, the flowrate versus time for all postulated breaks (both sides of the guillotine break).

<u>Moody Subcooled Liquid Blowdown Model</u>

To be conservative, the analyses were performed using the Subcooled Moody Blowdown Model. The Calculated Subcooled Moody Blowdown Model is an extension of the previously accepted saturated Moody blowdown model. This extended model is applicable to liquid blowdowns at an enthalpy lower than the saturated liquid enthalpy. The solution of the Moody model to obtain the critical mass flux values (G) conservatively views the flow as originating from a single high pressure node and discharging into standard atmosphere.

A complete description of the flow correlations and methods used for treating the air-steam-water mixture in subcompartment thermodynamics and fluid dynamics used in COPDA is provided in BN-TOP-4, Revision 0.[8]

Full-size copies of the following drawings submitted to the NRC were used to determine the subcompartment volumes and vent areas:

- *H 25680.*
- *H 25688.*
- *H 26105.*

- *SK-M-23, Revision D.*
- *SK-M-24, Revision D.*
- *JM 4069-22.*

For most cases, compartment boundaries were established at major flow restrictions.

The actual node volumes used as input to COPDA were calculated as follows:

- *Conservatively calculate the gross free node volumes excluding the volumes of instrumentation, piping, and any physical objects which occupy volume.*
- *Calculate the volumes of insulation in the nodes.*
- *Calculate the actual node volumes by subtracting the volumes of insulation from the gross free node volumes.*

The actual flow areas between adjacent nodes used as input to COPDA were calculated by similar procedures as mentioned above, that is, the actual flow areas were obtained by subtracting the areas of insulation from the conservatively calculated gross free-flow areas.

From these considerations, it can be seen that both the node volumes and the vent areas are lower bound values. This procedure is conservative for subcompartment pressure transient analyses. Consequently, the local pressure in the break node is an upper bound value and thus conservative. The pressure transients were again calculated using the COPDA computer program described in BN-TOP-4, Revision 0.[8]

The flow coefficient (C) for a particular geometry is determined as a function of the equivalent head loss coefficient (K_{eff}) for that flow system. The flow coefficient is expressed as:

$$C = \frac{1}{\sqrt{k_{eff}}}$$

The value of K_{eff} is simply the sum of the head losses for separate parts of the system. For the analyses performed in the RPV shield annulus and drywell head regions, head losses are defined as follows:

A. *Entrance Loss or Contraction*

This loss is determined as a function of the ratio of the upstream cross-sectional area to the cross-sectional area of the contraction.

B. *Exit Loss of Expansion*

This loss is determined as a function of the ratio of the cross-sectional area upstream of the expansion to the cross-sectional area downstream of the expansion. For the final expansion into the downstream compartment, a conservative expansion loss coefficient of 1.0 is generally assumed.

C. Resistance of Bends to Flow of Fluid

This resistance is determined by the angle and length of the bend.

D. Friction Losses

These losses, although generally very small, are calculated as an fℓ/d term.

The losses listed above are defined specifically in references 8, 9, and 10. Values of the components used in the feedwater, recirculation inlet and outlet, and head spray[a] line analyses are given in tables 6A-6 through 6A-10, respectively.

In general, for conservatism, insulation was assumed to be in place and uncrushed throughout the transient.

However, in the case of the feedwater line break, the location of the postulated break is just beneath the opening of the annulus to the drywell. The insulation in that opening was considered in a more realistic manner. It was assumed that in the break node, all the insulation is blown into the drywell. Furthermore, it was assumed that 50% of the insulation in the other nodes at the uppermost elevation in the annulus remains intact and that 50% is blown into the drywell.

For all postulated break cases, the insulation on piping and components was assumed to be uncrushed and in place. In addition, no credit was taken for flow through penetrations in the sacrificial shield. These assumptions ensure conservative results.

<u>Recirculation Outlet, Recirculation Inlet, and Feedwater</u>

In the annulus region between the RPV and the sacrificial shield, a 3-in. layer of insulation surrounds the RPV.

To calculate the vent areas and the node volumes for the recirculation outlet and inlet cases, it was assumed the insulation is intact after the break occurs; the volumes and the areas of insulation were excluded from the actual values used as input to COPDA.

For the feedwater line where the break is located much closer to the vertical flow area to the drywell, no insulation is assumed to block the flow area to the drywell from the compartment where the break occurs since the insulation is expected to be blown away from this area. For other compartments at the uppermost level, 50% of the insulation is assumed to block the flow areas from these compartments vertically to the drywell.

For all three breaks, all piping penetrations through the sacrificial shield were assumed to be completely blocked with insulation.

---

a. RPV head spray is deactivated; head spray information is maintained for historical purposes.

Head Spray[a] Line

For the analysis of the head spray line break, all insulation in the upper RPV shield annulus and head region is assumed to remain intact and uncrushed. Ventilation ducts in this region were also treated in this manner.

Effect of Extended Power Uprate[11, 12]

Three limiting breaks occur in the RPV shield annulus. The limiting breaks are located at the recirculation inlet, recirculation outlet, and feedwater line. To assess the impact of extended power uprate (2763 MWt) on annulus pressurization, the calculations pertaining to these breaks were subject to the new mass and energy release rates (MERs) presented in table 6A-5 (sheet 2 of 2). This review supports a conclusion that the documented application of the MERs for the original power of 2436 MWt produces annulus pressurization loads that bound those that would be calculated for extended power uprate conditions (2763 MWt). This conclusion remains applicable even though the extended power uprate break flow mass fluxes are higher in certain cases. The original calculations bound the three limiting breaks, because they are based upon conservative assumptions that provide sufficient margin to accommodate the MERs at the higher power level.

Effect of Thermal Power Optimization (TPO) and Reactor Operating Pressure Increase (ROPI)

There was no change to the blowdown mass and energy releases for the recirculation and feedwater lines provided by GE Nuclear Energy for TPO (thermal power level of 2804 MWt) under references 11 and 13. The impact of small increase in the mass and energy releases resulting from increase in reactor operating pressure from 1050 psia to 1060 psia has been evaluated under reference 14 with no significant impact.

6A.4.2 NODALIZATION SENSITIVITY STUDIES

Establishing the number of volume nodes necessary for a realistic calculation of the pressures in the node volumes during a LOCA generally demands considerable engineering judgment based upon experience and a close examination of the particular location of the break in the annulus region.

To ensure the number of volume nodes chosen are indeed appropriate, nodalization sensitivity studies were performed to evaluate the sensitivity of the results of COPDA calculations due to the variation of the number of nodes.

Intuitively one observes that, as the number of nodes increases, one may find pressures in some compartments increasing slightly as these compartments become smaller, while others are decreasing. This is due to the complexity introduced by the additional flowpaths in the calculation model. However, these increasing and decreasing effects offset each other, and the net effect should be evident in the forces and the moments on either the sacrificial shield or the RPV as a function of the number of nodes.

---

a. RPV head spray is deactivated; head spray information is maintained for historical purposes.

The feedwater line break, located at a much higher elevation than the recirculation outlet and inlet breaks, was selected for the nodalization sensitivity studies, because it offers the most severe moments on the RPV skirt support. Four nodalization studies are as follows:

1. Case A

   20 nodes, as shown in figure 6A-17, wherein nodes were added in the large volumes below the break (base case).

2. Case B

   16 nodes, as shown in figure 6A-18.

3. Case C

   28 nodes, as shown in figure 6A-19, wherein more nodes were added in the volumes below the break.

4. Case D

   27 nodes, as shown in figure 6A-20, wherein the region near the break were divided into a number of small nodes

The results of the study are as follows, with percentage changes in the moment on the RPV support skirt tabulated:

Case	Percentage	Nodes
A	0	20
B	- 2	16
C	+ 1	28
D	- 1	27

Note that Case A (20 nodes) was the base engineering model. The results of Case A are used for design purposes. It is expected Case D will exhibit the greatest sensitivity to nodalization, since extra nodes were added close to the break. Little sensitivity was noted, however. The numerical precision and engineering accuracy bounds of the solutions are considered to be larger than the scatter in the results noted above.

Circumferential and axial pressure variations were considered, as shown on figures 6A-17 through 6A-25. The pressure variations were < 2%.

The radial variation within a node was not considered, since the radial dimensions of the nodes in each model were much smaller than the axial or the circumferential dimensions of the nodes. Therefore, the radial pressure variations were assumed to be not as significant as the circumferential or the axial pressure variations.

Figures 6A-26 through 6A-32 provide the ΔP (psi) response as a function of time across compartment boundaries where the maximum ΔPs occur. Subcompartment models are shown on figures 6A-17, and 6A-21 through 6A-25. Differential pressure time-histories across all compartment boundaries can be obtained from figures 6A-26 through 6A-32. Compartment boundaries were established in areas where flow restrictions from structural components occur.

The peak ΔP and the time of occurrence of peak pressure for each break analyzed are shown in table 6A-10. The time of peak pressure and the peak ΔP for each node can be obtained from figures 6A-33 through 6A-36.

Figures 6A-37 through 6A-42 provide the resultant horizontal annulus pressure force vector and moment time-histories acting on the RPV and sacrificial shield wall for the feedwater, recirculation inlet, and recirculation outlet breaks in the annulus region. The moment is defined as the magnitude of the resultant horizontal annulus pressure force vector multiplied by the distance measured vertically from the foot of the RPV skirt to the point of application of this vector. As such, this force and moment represent forcing functions relative to an arbitrary datum line (the foot of the RPV skirt) and not a structural support reaction.

For the cases analyzed, figures 6A-37, 6A-39, and 6A-41 represent the resultant horizontal force in the x direction. Resultant forces in the y and z directions are zero. Figures 6A-38, 6A-40, and 6A-42 represent resultant moments about the y axis with resultant moments about the x and z axes being equal to zero. Figure 6A-43 provides the axis orientation for the resultant force and moment vectors.

Figure 6A-17, figures 6A-21 through 6A-25, and figure 6A-44 provide the schematic flow diagrams for the breaks analyzed in the shield annulus region and drywell head region. Figure 6A-45 provides a drawing of the feedwater sparger system, including appropriate flow areas.

Plots of pressure versus time for each node for the feedwater, recirculation inlet and recirculation outlet line breaks are provided in figures 6A-33 through 6A-36. Differential pressure for the head spray[a] line break is provided in figure 6A-46.

The design ΔPs for each major compartment are as follows:

- Reactor shield inside liner plate - 127 psid (uniform pressure distribution).

- Reactor refueling bellows - 18.4 psid (uniform pressure distribution).

- Drywell - 56.0 psid (uniform pressure distribution).

- Recirculation outlet inservice door (N1A, N1B):

  The N1 inservice inspection door detailed on figure 6A-47 (sheet 1) is a heavy metal shielding door supported on double-knuckle roller bearing hinges for ease of opening and closing. During normal plant operation, each leaf of this door is secured to the door frame by twelve 1 1/8-in. f A490 bolts. The door frame is welded to the sac shield framing with gusset plates (figure 6A-47, sheet 2).

a. RPV head spray is deactivated; head spray information is maintained for historical purposes.

The sac shield annulus study for nonaxisymmetric pressure distributions required the addition of a steel collar to the existing door structure to restrict the steam blowdown into the annulus. The restraint band and saddle arrangement shown on figure 6A-48 were provided to limit the pipe separation and consequent jet impingement force on the door face (figure 6A-12). The loadings used in the door reanalysis are as follows:

- An 85-psid pressure across the door face (figure 6A-36, sheet 1, nodes 1 and 2 minus node 3 at ~ 0.05 s).
- A maximum door penetration annulus pressure of 1065 psia. (The pressure profile across the width of the door was conservatively assumed to be constant and equal to the pressure in the recirculation line.)
- An upward pipe impact load on the door of 204 kips

NOTE: For conservatism, all loads were assumed to occur simultaneously.

The restraint band was designed using the work-energy methods outlined in BN-TOP-2, Revision 2. The work of the jet force in displacing the broken pipe was equated to the energy absorbed in plastically deforming the restraint structure. The calculated strain in the restraint was below the maximum allowed 50% of ultimate strain (0.5 eu), and the resulting dynamic load factor was 1.68.

The calculated dynamic load factor was applied to the pipe jet force, and the loading on the door was determined by static equilibrium. Door stresses were checked, not taking credit for the internal door reinforcing plates and the flow-restricting collar, and found to be within the code allowables.

The stresses on the door anchor bolts were determined from the above loadings, taking into account the eccentric nature of the oads with respect to the centerline of the anchor bolt resistance. These stresses were found to satisfy the provisions of American Institute of Steel Construction Section 1.6.3 with a 50% increase in allowable stresses for the accident condition. No credit was taken for the strength of the door hinges other than supporting the dead load of the door.

Stress results are tabulated below:

Door Stresses

Maximum Calculated Stress	Allowable Stress
25.92 ksi (tension)	32.4 ksi = 1.5 (0.6) F_y
20.74 ksi (compression)	32.4 ksi = 1.5 (0.6) F_y
5.4 ksi (shear)	18.7 ksi = 0.9 (F_y / Ö3) < 1.5 (0.4) F_y

Bolt Stresses

	Maximum Calculated Stress	Allowable Stress
Outermost bolt	24.81 ksi (shear)	33.75 ksi = 1.5 (22.5^{ksi})
	44.08 ksi (tension)	45.46 ksi = [70 - 1.6 (24.81ksi)] 1.5[(a)]
Innermost bolt	25.32 ksi (shear)	33.75 ksi = 1.5 (22.5^{ksi})
	19.50 ksi (tension)	44.23 ksi = [70 - 1.6 (25.32 ksi)] 1.5[(a)]

6A.4.3 DRYWELL AREA

Analyses for the upper and lower drywell regions regarding the pressure response in these areas from postulated ruptures of high-energy lines were completed. The following 13 lines in the drywell were analyzed:

1. Upper Drywell

   - Main steam.
   - Main feedwater.
   - CS.

2. Lower Drywell

   - Main steam.
   - Main feedwater.
   - Residual heat removal (RHR) suction.
   - RHR discharge.
   - Recirculation inlet.
   - Recirculation outlet.
   - High-pressure coolant injection (HPCI).
   - Reactor core isolation cooling (RCIC).
   - Reactor water cleanup (RWC).
   - Main steam condensate drain.

a. The minimum yield strength for these bolts (A-490) is 130 ksi.

Tables 6A-4 and 6A-5 provide a tabulation of the blowdown mass and energy release rates for the lines analyzed in the drywell at the original rated conditions of 2436 MWt. Figures 6A-13, 6A-14, 6A-15 and figures 6A-49 through 6A-56 provide this information in graphic form.

Each break analyzed was assumed to be an instantaneous double-ended guillotine rupture which resulted in the maximum flowrate of fluid and maximum release of energy. The break areas assumed for the lines analyzed in the drywell are provided in tables 6A-4 and 6A-5. The breaks analyzed were the worst-case breaks of those postulated in section 3.6.

The subcooled Moody blowdown model was used to calculate blowdown mass fluxes and enthalpies for the upper and lower drywell regions analyzed. Two of the analyzed drywell lines, the RWC and the main steam condensate drain line, used the Fauske two-phase critical flow model to calculate the mass flux and enthalpy. The pressure transients were calculated using the COPDA computer program described in BN-TOP-4, Revision 0[8], which was filed with the NRC on August 5, 1976.

The subcompartment thermodynamics and fluid dynamics are also provided in BN-TOP-4, Revision 0.[8]

For most cases, compartment boundaries were established at major flow restrictions; e.g., grating, structures, ducts, and large pipes.

The nodal volumes used as input to COPDA were calculated for the lower drywell region to the sacrificial shield annulus, the upper drywell region, and the drywell head region. Flow loss coefficients for the main steam line (upper drywell) and RHR discharge line (lower drywell) are given in tables 6A-11 and 6A-12, respectively.

Figures 6A-49 through 6A-56 show the break critical mass flux as a function of time for CS, RHR suction, RHR discharge, main steam line, main steam condensate, RCIC steam, RWC, and HPCI steam lines, respectively. Each of these breaks was evaluated in detail at the original power level of 2436 MWt. For the upper drywell region, the main steam line break results in the highest pressure response. For the lower drywell region, the RHR discharge break results in the highest pressure response. Figures 6A-57 through 6A-60 provide the schematic flow diagrams for the main steam line and RHR discharge line.

Plots of pressure versus time for each node of the main steam line break (upper drywell) and RHR discharge line break (lower drywell) are provided in figures 6A-61 and 6A-62, respectively. These analyses provide the highest pressure transient cases for the pipe breaks analyzed in the drywell. Table 6A-13 provides a tabulation of the maximum pressure in any compartment, as well as the maximum ΔP between any two adjacent compartments observed in the analysis of each postulated line break.

The pressures calculated for the original power of 2436 MWt bound those that were calculated for extended power uprate conditions (2763 MWt).[12] This conclusion applies even through the extended power uprate mass fluxes may be higher in certain cases. The original calculations are bounding, because they are based upon conservative assumptions that provide sufficient margin to accommodate increased mass and energy release rates at the higher power level.

There was no change to the blowdown mass and energy releases for the recirculation and feedwater lines provided by GE Nuclear Energy for TPO (thermal power level of 2804 MWt) under references 11 and 13. The impact of small increase in the mass and energy releases resulting from increase in reactor operating pressure from 1050 psia to 1060 psia has been evaluated under reference 14 with no significant impact.

REFERENCES

1. Krieger, F. D., "GE635 Users Manual for the SAMIS (Structural Analysis and Matrix Interpretive System) Computer Program," Co No. 715D223, March 15, 1971.

2. "Final Seismic Analysis Reactor Building and Internals," Bechtel Corporation, April 15, 1971.

3. GE drawing no. 761E917 "Reactor Pressure Vessel Mathematical Model."

4. Letter to F. C. Downey from T. J. McDonald, "Sacrificial Shield Subcompartment Pressurization Analysis Information Package," File A-19, 1/A-57, O/B-GE-1968, March 2, 1976.

5. Response to NRC Question 1.26, HNP-2 FSAR, 110.13.

6. Letter to F. C. Downey from T. J. McDonald, "Subcompartment Pressurization Analysis," File A-19, 1/A-57, 0/B-GE-1716, May 11, 1976.

7. Biggs, John M., "Introduction to Structural Dynamics," McGraw-Hill, 1964.

8. BN-TOP-4, "Subcompartment Pressure and Temperature Transient Analysis," Revision 0, July 1976.

9. Chik, I. E. Idel, "Handbook of Hydraulic Resistance Coefficients of Local Resistance and Friction," USAEC-TR- 6630, 1966.

10. Crane Co., "Flow of Fluids," Technical Paper No. 410, Engineering Division, New York, N. Y., 1969.

11. GE letter to G. K. McElroy (SNC) from C. H. Stoll, "AP Mass & Energy and Drywell & Torus Temperature Profiles," File 4.1.1, April 28, 1997.

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

13. GE Nuclear Energy letter to T. W. Long (SNC) from Michael Dick, “Continued Applicability of Extended Power Uprate Letter (GEH023) to TPO,” dated May 28, 2002.

14. RER 03-254, Reactor Operating Pressure Increase (ROPI) From 1050 psia to 1060 psia, Engineering Evaluations.

TABLE 6A-1

MAXIMUM VALUES OF DYNAMIC REACTION FOR RECIRCULATION OUTLET LINE BREAK

Location	Elevation Above RPV 0.0	Maximum Shear (kips)	Maximum Shear Time (s)	Maximum Moment (kips-in.)	Maximum Moment Time (s)
Base of RPV skirt	-16.0 in.	2193.0	0.028	141,600.0	0.04
Stabilizers	560.0 in.	654.1	0.044	-	-

TABLE 6A-2

EFFECT OF ACOUSTIC LOAD AT TIME OF MAXIMUM REACTION

Location	Elevation Above RPV 0.0	Shear (kips)	Shear Time (s)	Moment (kips-in.)	Moment Time (s)
Base of RPV skirt	-16.0 in.	33.3	0.028	-1674.0	0.04
Stabilizers	560.0 in.	21.7	0.044	-	-

Maximum Dynamic Reaction Due to Acoustic Load

Location	Elevation Above RPV 0.0	Shear (kips)	Shear Time (s)	Moment (kips-in.)	Moment Time (s)
Base of RPV skirt	-16.0 in.	-62.1	0.0078	3148.0	0.0718
Stabilizers	560.0 in.	29.7	0.0472	-	-

TABLE 6A-3

**MAXIMUM VALUES OF DYNAMIC REACTION
FOR
FEEDWATER LINE BREAK**

Location	Elevation Above RPV 0.0	Maximum Shear (kips)	Maximum Shear Time (s)	Maximum Moment (kips-in.)	Maximum Moment Time (s)
Base of RPV skirt	-16.0 in.	472.0	0.064	64,960.0	0.028
Stabilizers	560.0 in.	718.0	0.028	-	-

TABLE 6A-4 (SHEET 1 OF 2)

BLOWDOWN MASS, ENERGY RELEASE RATE, AND BREAK AREAS FOR LINES IN DRYWELL

		Vessel Side			Inventory Side		
System	Time (s)	G (lb/ft^2-s)	h (Btu/lb)	Area (ft^2)	G (lb/ft^2-s)	h (Btu/lb)	Area (ft^2)
Main steam line break (MSLB) (upper and lower drywell)	0 to 1	2160	1190	2.601	-	-	-
	1 to 5 (steam)	300	1190	2.601	-	-	-
	1 to 5 (liquid)	7280	550	2.601	-	-	-
	0 to 0.135	1620	1190	3.1415	-	-	-
	0.135 to 1.0	-	-	-	2160	1190	0.655
	1 to 5 (steam)	-	-	-	300	1190	0.655
	1 to 5 (liquid)	-	-	-	7280	550	0.655
RHR suction[c]	0 to 0.2	9500	525	1.75	9500	525	1.75
	0.2 to 0.5	9500	525	1.75	0	0	-
RHR discharge	0 to 0.7	9500	525	2.54	4000	525	2.54
	0.7 to 1.0	9500	525	2.54	0	0	-
Recirculation outlet (annulus)[b]							
Recirculation inlet[b]							
Feedwater (lower and upper drywell)[b]							
HPCI steam	0 to 1	2160	1190	0.4732	-	-	-
	1 to 5 (steam)	300	1190	0.4732	-	-	-
	1 to 5 (liquid)	7280	550	0.4732	-	-	-
	0 to 4.19	-	-	-	2160	1190	0.4732
RCIC steam	0 to 1	2160	1190	0.07163	-	-	-
	1 to 5 (steam)	300	1190	0.07163	-	-	-
	1 to 5 (liquid)	7280	550	0.01763	-	-	-
	0 to 3.8	-	-	-	2160	1190	0.07163

TABLE 6A-4 (SHEET 2 OF 2)

		Vessel Side			Inventory Side		
System	Time (s)	G (lb/ft^2-s)	h (Btu/lb)	Area (ft^2)	G (lb/ft^2-s)	h (Btu/lb)	Area (ft^2)
CS	0 to 5	9500	525	0.5185	0	0	-
Main steam condensate drain	0 to 0.0998	9467	542.4	0.0375	9467	542.4	0.0375
	0.0998 to 0.131	2000	1191	0.0155	9467	542.4	0.0375
	0.131 to 3.0	2000	1191	0.0155	2000	1191	0.0155
RWC[c]	0 to 0.452	9467	542.4	0.181	9467	542.4	0.181
	0.452 to 5.0	9467	542.4	0.181	-	-	-

a. The mass fluxes (G) and enthalpies (h) shown are for the original core rated thermal power level of 2436 MWt.
b. See table 6A-5.
c. The enthalpies used for the high-energy line break analysis are for the subcooled conditions.

TABLE 6A-5 (SHEET 1 OF 2)

BLOWDOWN MASS, ENERGY RELEASE RATE, AND BREAK AREAS
FOR
RECIRCULATION OUTLET AND INLET, FEEDWATER, AND HEAD SPRAY LINES

A. ORIGINAL RATED CONDITIONS - RTP OF 2436 MWt[a]

Vessel Side[b]

	Recirculation Outlet	Recirculation Inlet		Feedwater			Head Spray[c]
Time (s)	0 to 5	0 to 0.132	0.132 to 5	0 to 5			0 to 5
G (lb/ft^2-s)	9500	4000	9500	9500			2100
h (Btu/lb)	525	525	525	525			1190
Area (ft^2)	0.78[d]	0.723[e]	0.1262[f][g]	0.521[h][i]			0.165(j)

Inventory Side[b]

	Recirculation Outlet	Recirculation Inlet		Feedwater			Head Spray
Time (s)	0 to 5	0 to 0.22	0.22 to 5	0 to 1.57	1.57 to 3.76	3.76 to 5	0 to 5
G (lb/ft^2-s)	9500	4000	9500	2360	6650	9500	0
h (Btu/lb)	525	550	525	402	402	525	0
Area (ft^2)	0.78	0.706		0.668			

TABLE 6A-5 (SHEET 2 OF 2)

B. RATED THERMAL POWER LEVEL OF 2804 MWt [m]

	Recirculation Outlet	Recirculation Inlet		Feedwater		
Vessel Side						
Time (s)	0 to 5	0 to 0.132	0.132	0 to 5		
G (lbm/ft^2-s)	10,500	4,000	10,500	10,500		
h (Btu/lbm)	516.3	516.3	516.3	516.3		
Area (ft^2)	0.78[d]	0.723[e]	0.1262[g]	0.521[i]		
Inventory Side						
Time (s)	0 to 5	0 to 0.22	0.22 to 5	0 to 1.57	1.57 to 3.76	3.76 to 5
G (lbm/ft^2-s)	10,500	4000	10,500	2360	6650	10,500
h (Btu/lbm)	516.3	516.3	516.3	405.6	405.6	516.3
Area (ft^2)	0.78	0.706[k]	0.706	0.668	0.668	0.668[l]

a. Values and plots currently in tables 6.A-6 through 6A-10 and figures 6.A-13 through 6A-42 are based upon sheet 1 of this table.
b. Each break analyzed was assumed to be an instantaneous guillotine rupture resulting in breakflow from both sides of the severed pipe. Vessel" refers to the side of the broken pipe having the shortest route to the RPV. "Inventory" refers to the section of pipe on the other side of the break. "Safe-end area" refers to the minimum-flow area of the nozzle safe-end installed between the forged nozzle of the RPV and the particular pipe of interest.
c. RPV head spray is deactivated.
d. Flow area into the annulus bounded by the safe-end outer diameter for the recirculation outlet nozzle and inner diameter of the door penetration (figure 6A-12). The area is considered to be free of insulation.
e. Safe-end area.
f. Based upon a 3.4-in. inner diameter of one jet pump nozzle (figure 4.2-4).
g. Nozzle area of two jet pumps.
h. Based upon a 9.75 ± 0.03-in. diameter of the feedwater sparger safe-end.
i. Area of one feedwater sparger safe-end.
j. Head spray line area.
k. Area of recirculation riser pipe.
l. Area of feedwater riser pipe.
m. The impact on the mass and energy releases for reactor operating pressure of 1060 psia has been evaluated under reference 14 with no significant impact on evaluation performed for thermal power optimization.

TABLE 6A-6 (SHEET 1 OF 2)

FEEDWATER LINE (20 NODES)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 2	0.05	1.0	0.45	-	0.82
1 → 3	0.07	1.0	-	0.0606	0.94
1 → 4	0.05	1.0	0.30	-	0.86
1 → 8	-	1.0	-	0.098	0.95
2 → 3	0.27	1.0	-	0.0606	0.86
2 → 7	0.05	1.0	0.45	0.098	0.82
2 → 11	-	1.0	-	-	0.95
3 → 4	0.07	1.0	-	0.0606	0.94
3 → 5	0.27	1.0	-	0.0606	0.86
3 → 6	0.07	1.0	-	0.0606	0.94
3 → 7	0.07	1.0	-	0.0606	0.94
3 → 20	-	1.0	-	1.777	0.60
4 → 5	0.05	1.0	0.45	-	0.82
4 → 8	-	1.0	-	0.098	0.95
5 → 6	0.05	1.0	0.45	-	0.82
5 → 9		1.0	-	0.098	0.95
6 → 7	0.05	1.0	0.30	-	0.86
6 → 10	-	1.0	-	0.098	0.95
7 → 10	-	1.0	-	0.098	0.95
8 → 9	-	1.0	0.60	-	0.79

TABLE 6A-6 (SHEET 2 OF 2)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
8 → 11	-	1.0	0.60	-	0.79
8 → 13	-	1.0	-	0.1332	0.94
9 → 10	-	1.0	0.60	-	0.79
9 → 14	-	1.0	-	0.1332	0.94
10 → 11	-	1.0	0.60	-	0.79
10 → 15	-	1.0	-	0.1332	0.94
11 → 12	-	1.0	-	0.1332	0.94
12 → 13	-	1.0	0.60	-	0.79
12 → 15	-	1.0	0.60	-	0.79
12 → 17	0.14	1.0	0.60	-	0.85
13 → 14	-	1.0	0.60	-	0.79
13 → 18	0.14	1.0	-	0.22	0.85
14 → 15	-	1.0	0.60	-	0.79
14 → 19	0.14	1.0		0.22	0.85
15 → 16	0.14	1.0	0.60	-	0.85
16 → 17	-	1.0	0.60	-	0.79
16 → 19	-	1.0	0.60	-	0.79
17 → 18	-	1.0	0.60	-	0.79
18 → 19	-	1.0	0.60	-	0.79

TABLE 6A-7 (SHEET 1 OF 3)

RECIRCULATION OUTLET

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 4	0.05	1.0	0.2	-	0.89
1 → 9	-	1.0	-	0.0843	0.96
1 → 13	-	1.0	-	0.1132	0.94
2 → 4	0.05	1.0	0.2	-	0.89
2 → 9	-	1.0	-	0.0843	0.96
2 → 13	-	1.0	-	0.1132	0.94
3 → 20	0.3	1.0	-	0.1213	0.84
3 → 21	0.18	1.0	-	0.1213	0.88
3 → 22	0.3	1.0	-	0.1213	0.84
3 → 25	-	1.0	-	1.777	0.60
4 → 5	0.05	1.0	0.2	-	0.89
4 → 10	-	1.0	-	0.0843	0.96
4 → 14	-	1.0	-	0.1132	0.94
5 → 6	0.05	1.0	0.2	-	0.89
5 → 10	-	1.0	-	0.0843	0.96
5 → 14	-	1.0	-	0.1132	0.94
6 → 7	0.05	1.0	0.2	-	0.89
6 → 11	-	1.0	-	0.0843	0.96
6 → 15	-	1.0	-	0.1132	0.94
7 → 8	0.05	1.0	0.2	-	0.89
7 → 11	-	1.0	-	0.0843	0.96

TABLE 6A-7 (SHEET 2 OF 3)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
7 → 15	-	1.0	-	0.1132	0.94
8 → 12	-	1.0	-	0.0843	0.96
8 → 16	-	1.0	-	0.1132	0.94
9 → 10	-	1.0	0.4	-	0.85
9 → 23	-	1.0	-	0.0615	0.97
10 → 11	-	1.0	0.4	-	0.85
10 → 23	-	1.0	-	0.0615	0.97
11 → 12	-	1.0	0.4	-	0.85
11 → 24	-	1.0	-	0.0615	0.97
12 → 24	-	1.0	-	0.0615	0.97
13 → 14	-	1.0	0.4	-	0.85
13 → 17	-	1.0	-	0.0986	0.95
14 → 15	-	1.0	0.4	-	0.85
14 → 17	-	1.0	-	0.0986	0.95
14 → 18	-	1.0	-	0.0986	0.95
15 → 16	-	1.0	0.4	-	0.85
15 → 18	-	1.0	-	0.0986	0.95
15 → 19	-	1.0	-	0.0986	0.95
16 → 19	-	1.0	-	0.0986	0.95
17 → 18	-	1.0	0.60	-	0.79
17 → 20	-	1.0	-	0.0986	0.95
18 → 19	-	1.0	0.60	-	0.79

TABLE 6A-7 (SHEET 3 OF 3)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
18 → 21	-	1.0	-	0.0986	0.95
19 → 22	-	1.0	-	0.0986	0.95
20 → 21	-	1.0	0.60	-	0.79
21 → 22	-	1.0	0.60	-	0.79
23 → 24	-	1.0	1.04	-	0.70

TABLE 6A-8 (SHEET 1 OF 3)

RECIRCULATION INLET

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 2	0.05	1.0	0.2	-	0.89
1 → 3	0.29	1.0	-	0.1179	0.84
1 → 8	-	1.0	-	0.0843	0.96
1 → 14	-	1.0	-	0.1132	0.94
2 → 4	0.05	1.0	0.2	-	0.89
2 → 9	-	1.0	-	0.0843	0.96
2 → 15	-	1.0	-	0.1132	0.94
3 → 21	0.18	1.0	-	0.1213	0.88
3 → 22	0.3	1.0	-	0.1213	0.84
3 → 23	0.18	1.0	-	0.1213	0.88
3 → 24	-	1.0	-	1.77	0.60
4 → 5	-	1.0	-	0.1213	0.88
4 → 9	-	1.0	-	0.0843	0.96
4 → 15	-	1.0	-	0.1132	0.94
5 → 6	0.05	1.0	0.2	-	0.89
5 → 10	-	1.0	-	0.0843	0.96
5 → 16	-	1.0	-	0.1132	0.94
6 → 7	0.05	1.0	0.2	-	0.89
6 → 10	-	1.0	-	0.0843	0.96

TABLE 6A-8 (SHEET 2 OF 3)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
6 → 16	-	1.0	-	0.1132	0.94
7 → 11	-	1.0	-	0.0843	0.96
7 → 17	-	1.0	-	0.1132	0.94
8 → 9	-	1.0	0.4	-	0.85
8 → 12	-	1.0	-	0.0615	0.97
9 → 10	-	1.0	0.4	-	0.85
9 → 12	-	1.0	-	0.0615	0.97
10 → 11	-	1.0	0.4	-	0.85
10 → 13	-	1.0		0.0615	0.97
11 → 13	-	1.0		0.0615	0.97
12 → 13	-	1.0	1.04	-	0.7
14 → 15	-	1.0	0.4	-	0.85
14 → 18	-	1.0	-	0.1094	0.95
15 → 16	-	1.0	0.04	-	0.85
15 → 18	-	1.0		0.1096	0.95
15 → 19	-	1.0		0.1096	0.94
16 → 17	-	1.0	0.04	-	0.85
16 → 19	-	1.0	-	0.1094	0.95
16 → 20	-	1.0	-	0.1096	0.95
17 → 20	-	1.0	-	0.1094	0.95

TABLE 6A-8 (SHEET 3 OF 3)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
18 → 19	-	1.0	0.6	-	0.79
18 → 21	-	1.0	-	0.0986	0.95
19 → 20	-	1.0	0.6	-	0.79
19 → 22	-	1.0	-	0.0986	0.95
20 → 23	-	1.0	-	0.0986	0.95
21 → 22	0.05	1.0	-	-	0.79
22 → 23	0.05	1.0	-	-	0.79

TABLE 6A-9

HEAD SPRAY[a] LINE

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 2	0.10	1.0	0.56	0.134	0.75
1 → 2	-	-	-	-	Orifice[b]

a. RPV head spray is deactivated; head spray information is maintained for historical purposes.
b. See reference 1.

TABLE 6A-10

PEAK PRESSURE TABLE (ANNULUS)

System	Peak Absolute (psia)	Time (s)	Peak Differential[a] (psid)	Time (s)
Recirculation outlet	98.78	0.33	84.42	0.03
Recirculation inlet	83.96	1.00	68.0	0.98
Feedwater	114.49	3.79	96.0	3.79
CS	40.22	1.00	23.9	0.31
Head spray[b]	25.64	2.00	9.0	1.30

a. Maximum differential pressure across two adjacent compartments.
b. RPV head spray is deactivated; head spray information is maintained for historical purposes.

TABLE 6A-11 (SHEET 1 OF 4)

MAIN STEAM LINE BREAK (UPPER DRYWELL)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 2	0.14	1.0	0.135	-	0.886
1 → 3	0.14	1.0	0.135	-	0.886
1 → 10	-	1.0	0.04	-	0.981
1 → 10	-	-	-	-	Orifice
2 → 4	0.10	1.0	0.13	-	0.90
2 → 9	-	-	-	-	Orifice
2 → 11	-	1.0	-	0.012	0.99
2 → 11	-	-	-	-	Orifice
3 → 5	0.10	1.0	0.13	-	0.90
3 → 12	-	-	-	-	Orifice
3 → 12	0.02	1.0	-	0.01	0.985
4 → 6	0.10	1.0	0.13	-	0.90
4 → 11	0.04	1.0	-	0.01	0.976
5 → 7	0.10	1.0	0.13	-	0.90
5 → 12	0.04	1.0	-	0.01	0.976
6 → 8	0.14	1.0	0.135	-	0.886
6 → 11	0.02	1.0	-	0.01	0.985
6 → 11	-	-	-	-	Orifice
7 → 8	0.14	1.0	0.135	-	0.886
7 → 9	-	-	-	-	Orifice

TABLE 6A-11 (SHEET 2 OF 4)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
7 → 12	-	-	-	0.012	0.99
7 → 12	-	-	-	-	Orifice
8 → 9	-	-	-	-	Orifice
8 → 13	-	1.0	0.04	-	0.981
8 → 13	-	-	-	-	Orifice
9 → 21	0.10	1.0	0.647	0.371	0.746[a]
9 → 22	0.10	1.0	0.647	0.371	0.746[a]
10 → 11	0.11	1.0	-	0.071	0.92
10 → 12	0.11	1.0	-	0.071	0.92
10 → 14	0.41	1.0	-	0.094	0.82
10 → 16	0.41	1.0	-	0.094	0.82
10 → 20	0.15	1.0	-	0.022	0.92
11 → 13	0.11	1.0	-	0.071	0.92
11 → 21	0.12	1.0	-	0.018	0.94
11 → 14	0.36	1.0	-	0.171	0.81
11 → 15	0.36	1.0	-	0.171	0.81
12 → 13	0.11	1.0	-	0.071	0.92
12 → 16	0.36	1.0	-	0.171	0.81
12 → 17	0.36	1.0	-	0.171	0.81
12 → 22	0.12	1.0	-	0.018	0.94
13 → 15	0.41	1.0	-	0.094	0.82

a. Area weighted average.

TABLE 6A-11 (SHEET 3 OF 4)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
13 → 17	0.41	1.0	-	0.094	0.82
13 → 23	0.15	1.0	-	0.022	0.92
14 → 15	0.02	1.0	-	0.60	0.79
14 → 16	0.02	1.0	-	0.60	0.79
14 → 18	0.18	1.0	-	0.014	0.92
15 → 17	0.02	1.0	-	0.60	0.79
15 → 19	0.18	1.0	-	0.014	0.92
16 → 17	0.02	1.0	-	0.60	0.79
16 → 18	0.18	1.0	-	0.014	0.92
17 → 19	0.18	1.0	-	0.014	0.92
18 → 19	0.05	1.0	-	1.0	0.70
20 → 21	0.28	1.0	-	0.256	0.81
20 → 22	0.28	1.0	-	0.256	0.81
20 → 24	-	-	-	-	Orifice
21 → 23	0.28	1.0	-	0.256	0.81
21 → 25	-	-	-	-	Orifice
22 → 23	0.28	1.0	-	0.256	0.81
22 → 26	-	-	-	-	Orifice
24 → 25	0.27	1.0	-	0.185	0.83
23 → 27	-	-	-	-	Orifice
24 → 26	0.27	1.0	-	0.185	0.83

TABLE 6A-11 (SHEET 4 OF 4)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
24 → 28	0.26	1.0	-	0.057	0.87
25 → 27	0.27	1.0	-	0.185	0.83
25 → 28	0.05	1.0	-	0.037	0.96
25 → 29	0.05	1.0	-	0.037	0.96
26 → 27	0.27	1.0	-	0.185	0.83
26 → 28	0.08	1.0	-	0.032	0.95
26 → 29	0.08	1.0	-	0.032	0.95
27 → 29	0.26	1.0	-	0.057	0.87
28 → 29	0.05	1.0	-	0.120	0.92
28 → 30	0.06	1.0	-	0.009	0.97
28 → 31	0.06	1.0	-	0.009	0.97
29 → 30	0.06	1.0	-	0.009	0.97
29 → 31	0.06	1.0	-	0.009	0.97
30 → 31	0.38	1.0	-	-	0.76
30 → 32	-	-	-	-	Orifice
32 → 33	0.05	1.0	-	-	0.95
31 → 33	-	-	-	-	Orifice
34 → 35	0.44	1.0	1.12	-	0.61
32 → 34	-	-	-	-	Orifice
33 → 34	-	-	-	-	Orifice

TABLE 6A-12 (SHEET 1 OF 2)

RHR DISCHARGE LINE (LOWER DRYWELL)

Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
1 → 2	-	-	-	-	Orifice
1 → 3	-	-	-	-	Orifice
1 → 4	0.043	1.0	0.096	-	0.93
1 → 4	-	-	-	-	Orifice
1 → 5	0.06	1.0	-		0.97
1 → 5	-	-	-	-	Orifice
1 → 6	0.23	1.0	0.08	-	0.87
2 → 8	0.055	1.0	1.0	-	0.93
2 → 12	-	-	-	-	Orifice
3 → 2	0.06	1.0	0.13	-	0.92
3 → 9	0.04	1.0	0.13	-	0.92
3 → 12	-	-	-	-	Orifice
4 → 2	-	-	-	-	Orifice
4 → 7	0.094	1.0	0.057		0.93
4 → 8	-	-	-	-	Orifice
4 → 10	0.02	1.0	-	-	0.99
5 → 4	0.028	1.0	0.07	-	0.95
5 → 10	0.080	1.0	-	-	0.95
5 → 10	-	-	-	-	Orifice
6 → 3	-	-	-	-	Orifice

TABLE 6A-12 (SHEET 2 OF 2)

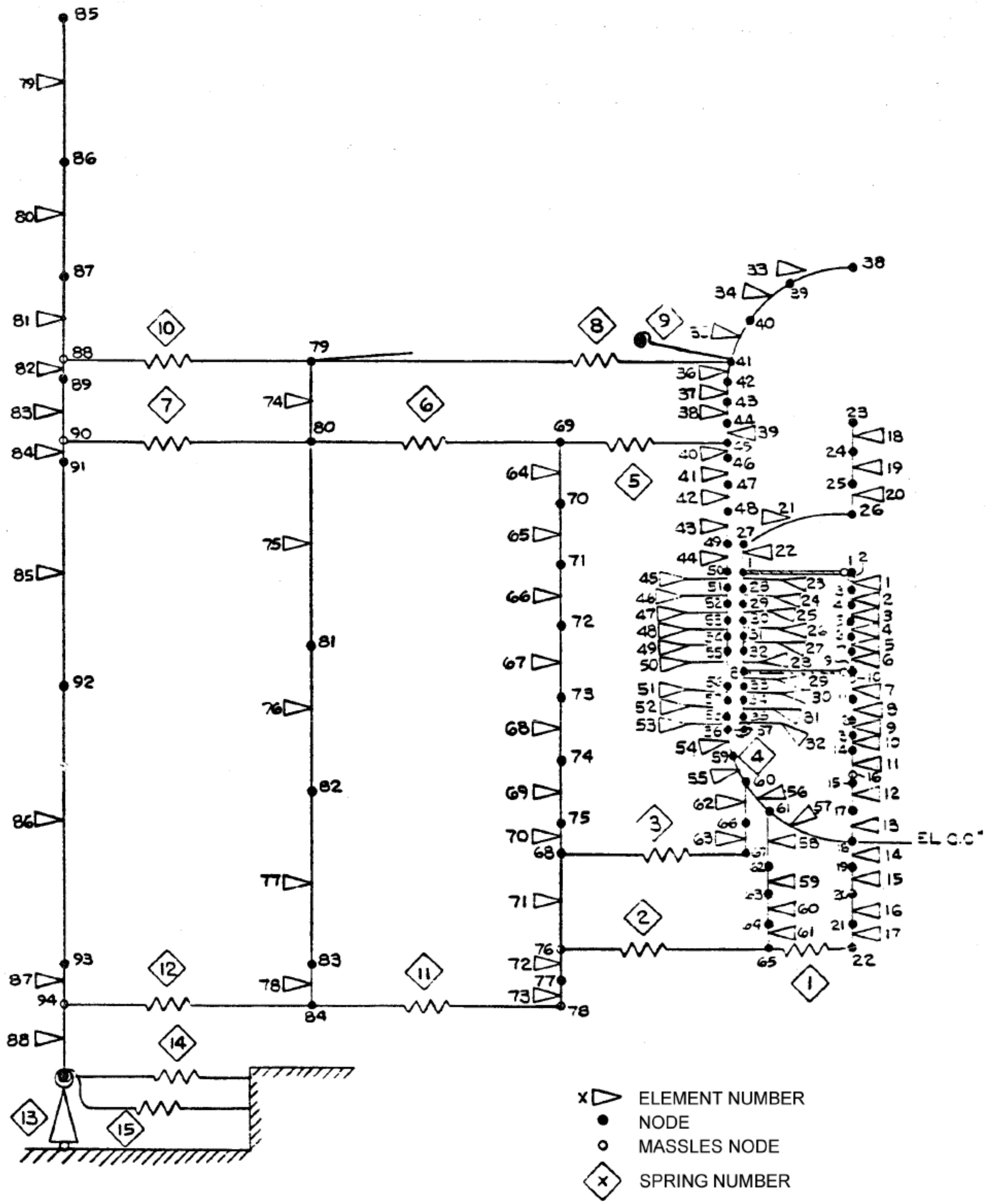
Flowpath	K Contraction	K Expansion	K Bending	K Friction	C
6 → 5	0.06	1.0	0.03	-	0.95
6 → 5	-	-	-	-	Orifice
6 → 9	-	-	-	-	Orifice
6 → 10	0.02	1.0	-	-	0.99
6 → 7	0.084	1.0	0.084	-	0.92
7 → 8	-	-	-	-	Orifice
7 → 9	-	-	-	-	Orifice
7 → 10	0.053	1.0	0.045	-	0.95
7 → 10	-	-	-	-	Orifice
8 → 12	-	-	-	-	Orifice
9 → 8	0.055	1.0	0.12		0.92
9 → 12	-	-	-	-	Orifice
10 → 11	-	-	-	-	Orifice
11 → 13	0.35	1.0	0.25	-	0.79
12 → 14	0.94	1.0	0.74	-	0.61

TABLE 6A-13

PEAK PRESSURE TABLE (DRYWELL)

System	Peak Absolute (psia)	Time (s)	Peak Differential[a] (psid)	Time (s)
MSL break - lower drywell	32.91	0.733	2.70	0.01
Recirculation outlet break - lower drywell	21.33	0.50	1.20	0.04
RHR suction break - lower drywell	22.87	0.30	0.94	0.04
Recirculation inlet	17.60	0.40	< 0.2	< 0.1
Feedwater break - lower drywell	19.60	2.00	0.7	2.00
HPCI break - lower drywell	23.00	1.50	0.6	0.95
Feedwater break - upper drywell	26.91	4.50	4.32	4.00
CS	20.52	2.35	2.8	0.08
RCIC break - lower drywell	16.56	2.00	1.39	1.00
Main steam condensate drain	15.08	2.27	0.06	0.1
RWC	23.49	5.00	0.2	0.11

a. Maximum differential pressure across two adjacent compartments.

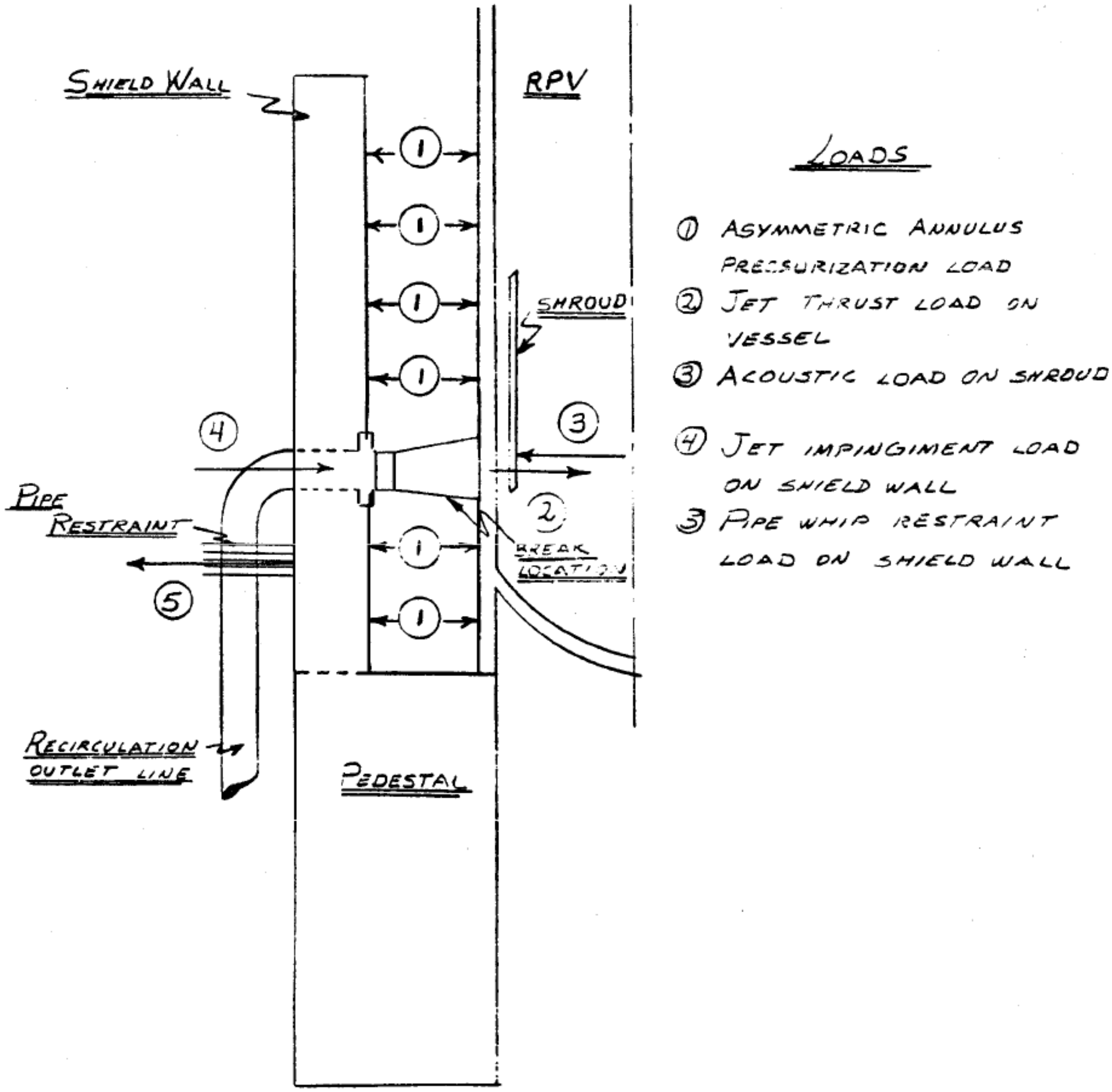


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SAMIS – DYNAMIC MODEL

FIGURE 6A-1

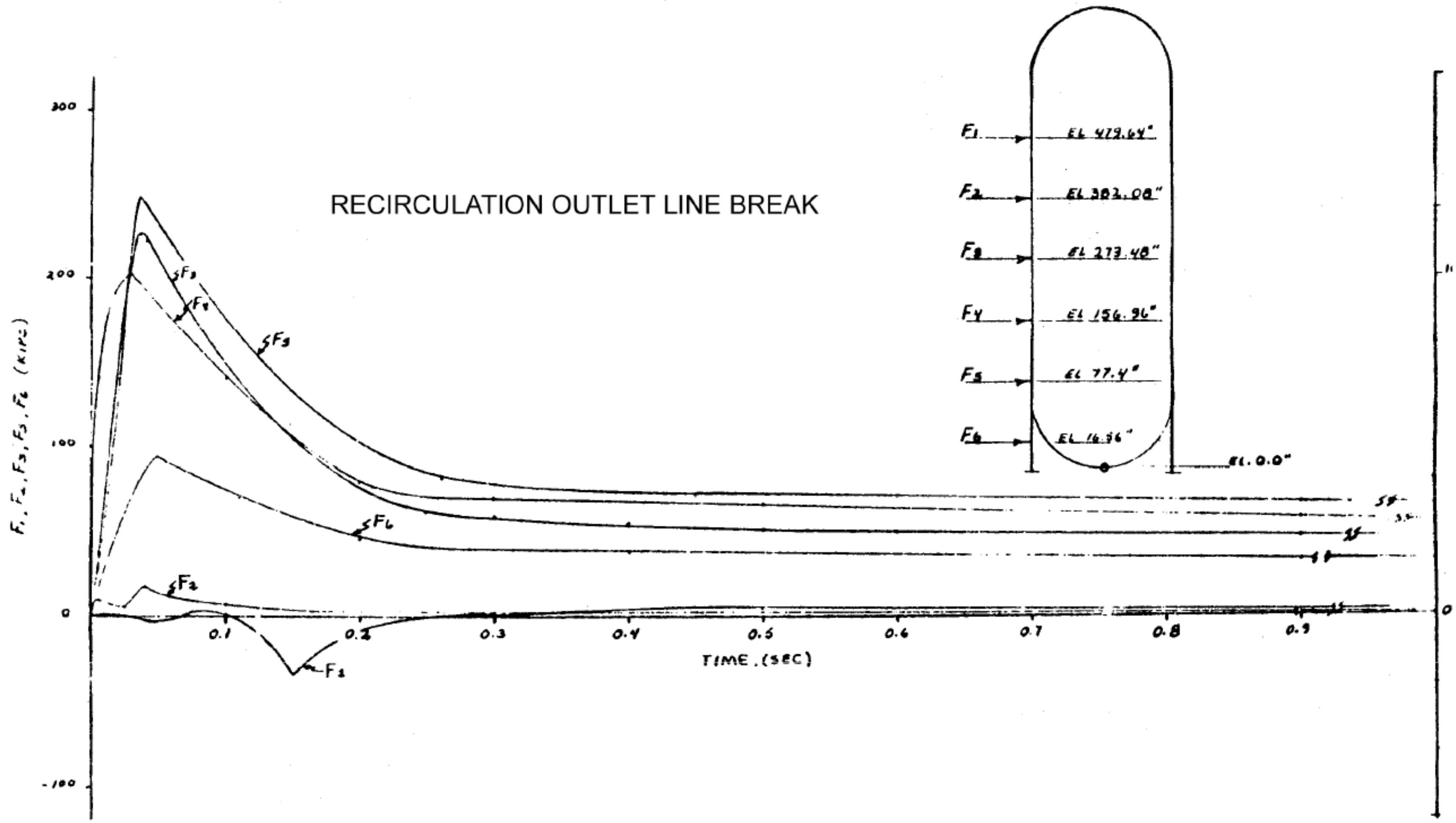


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LOADS FOR RECIRCULATION OUTLET LINE BREAK

FIGURE 6A-2



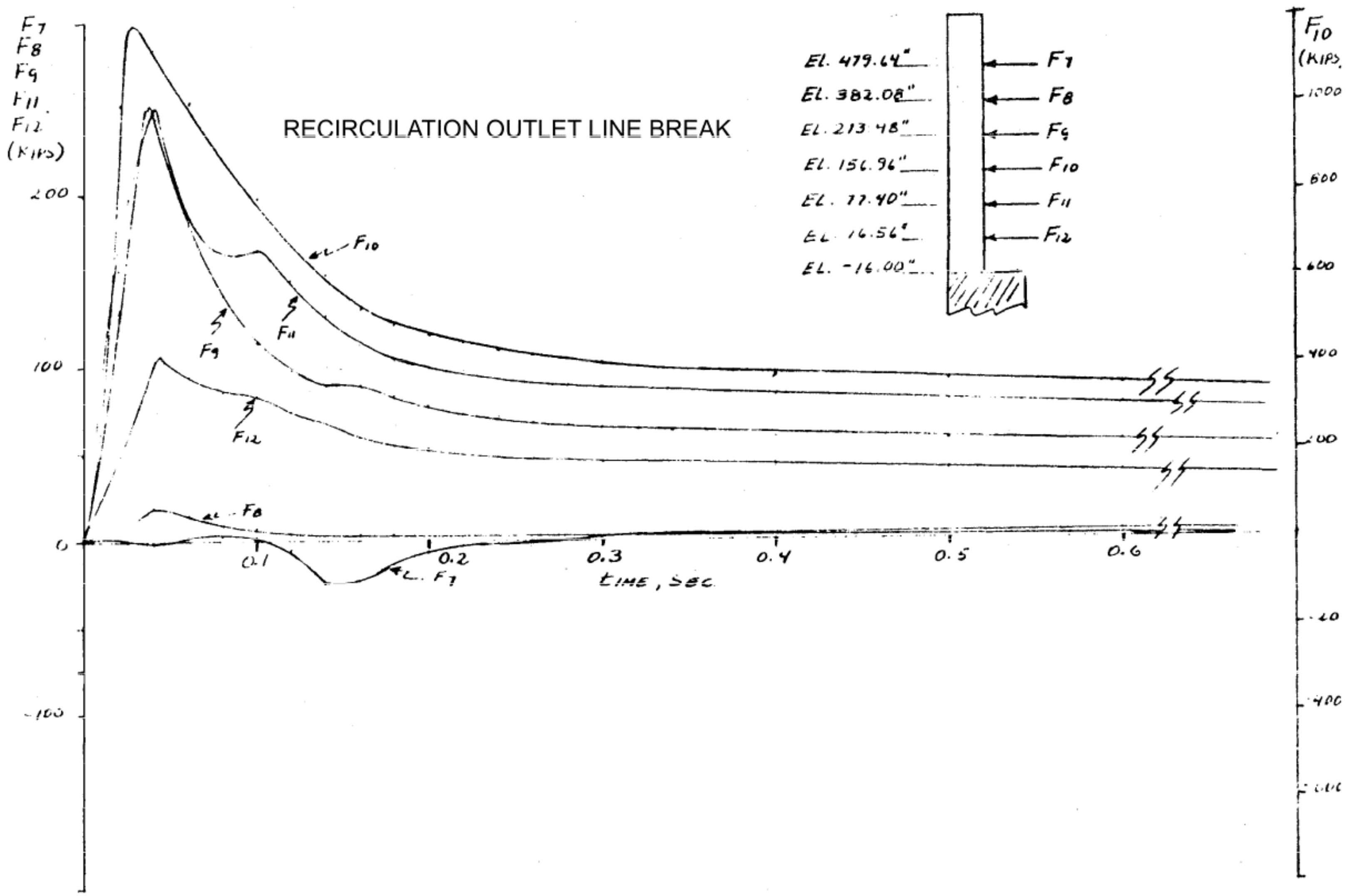
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FORCES ON RPV

FIGURE 6A-3

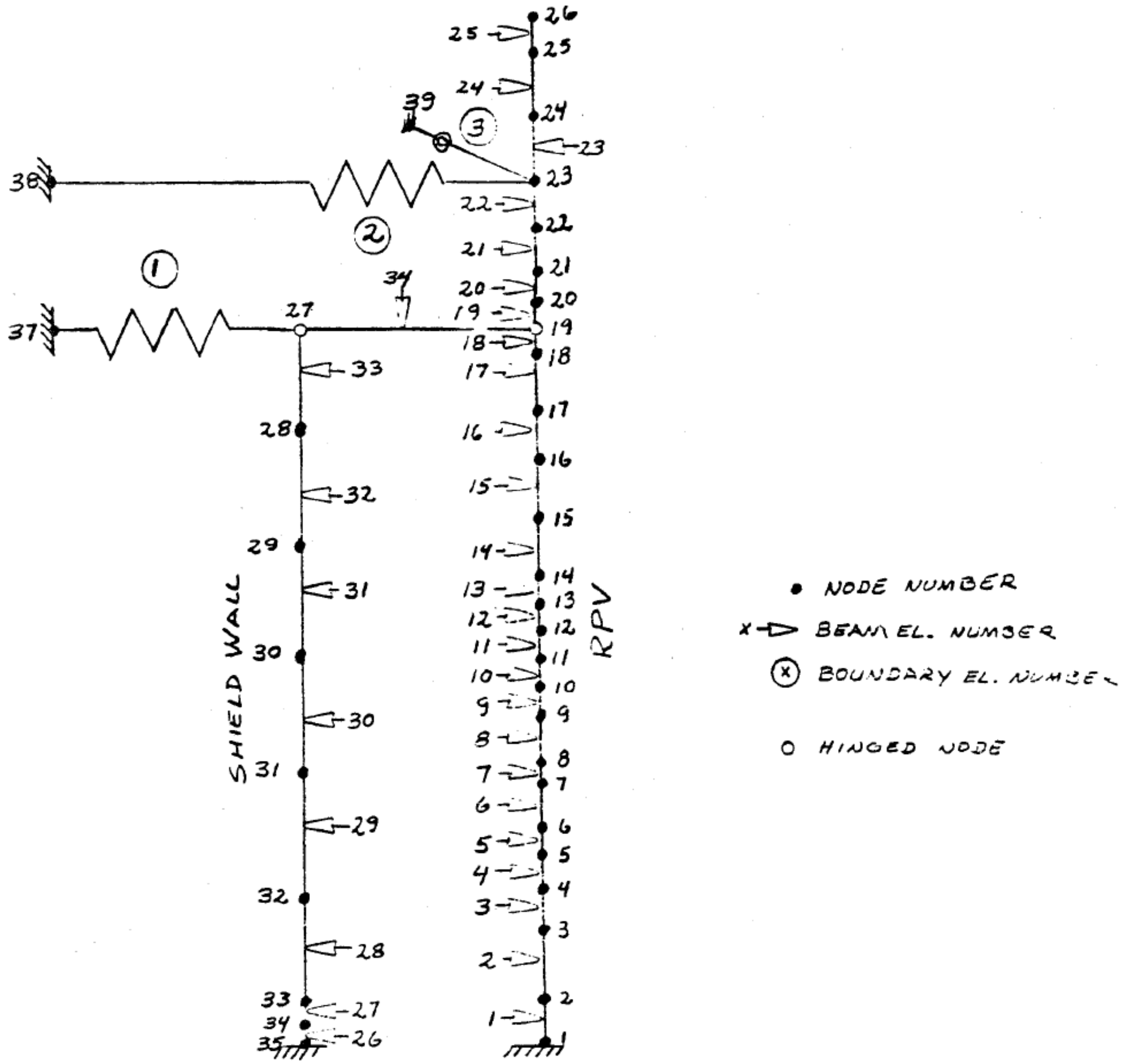


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FORCES ON SHIELD WALL

FIGURE 6A-4

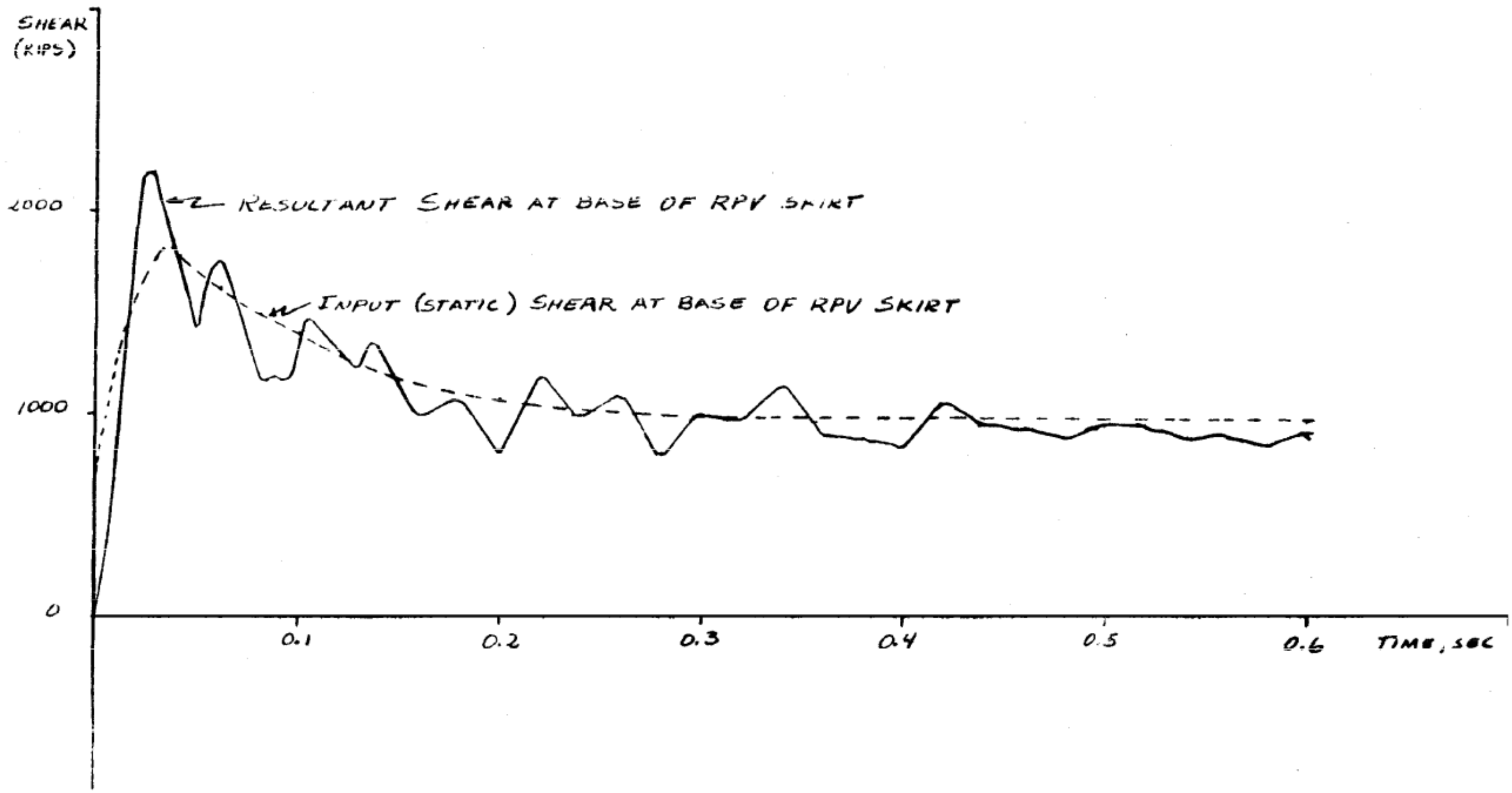


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SAP STATIC ANALYSIS MODEL

FIGURE 6A-5



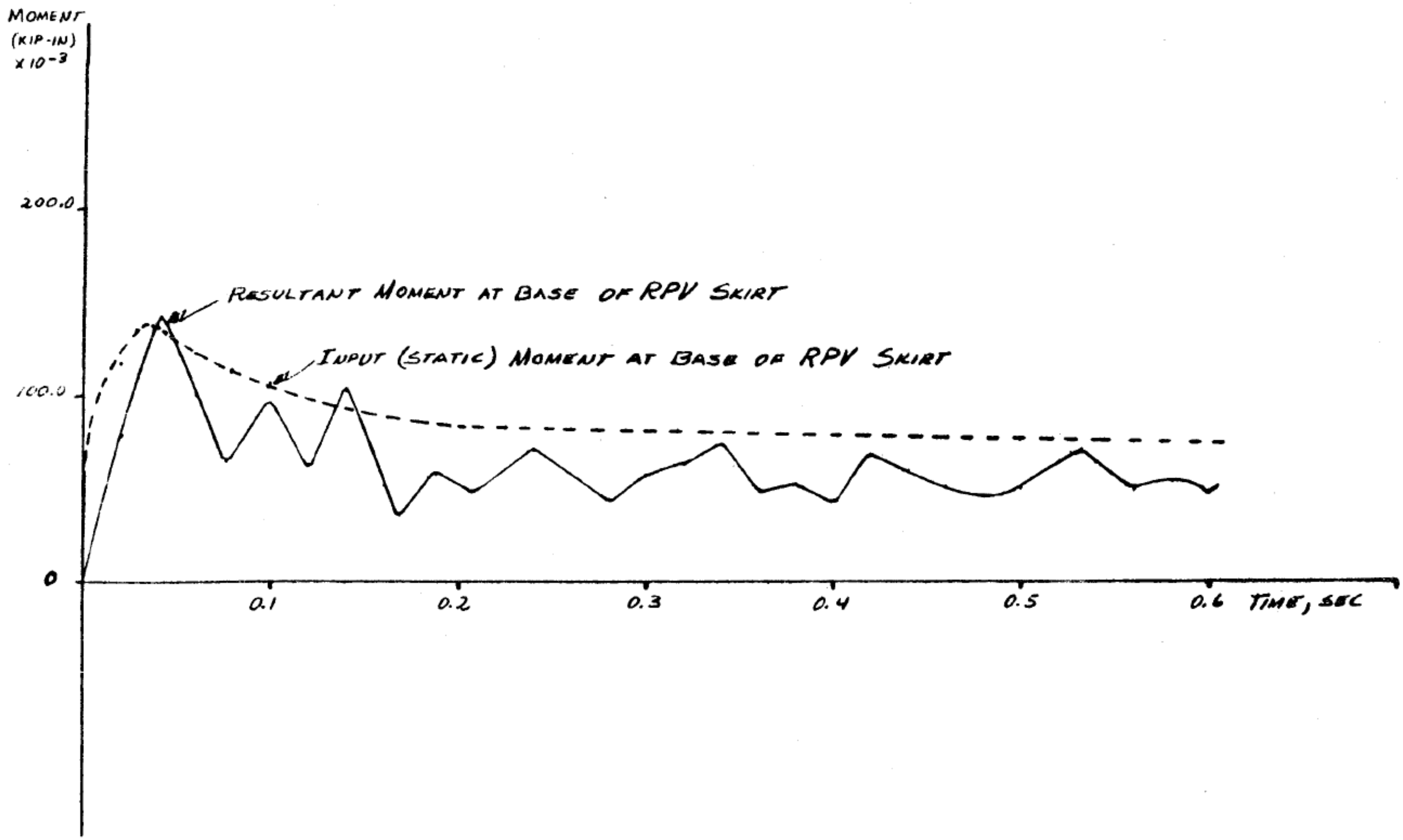
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET LINE BREAK RESULTANT SHEAR

FIGURE 6A-6



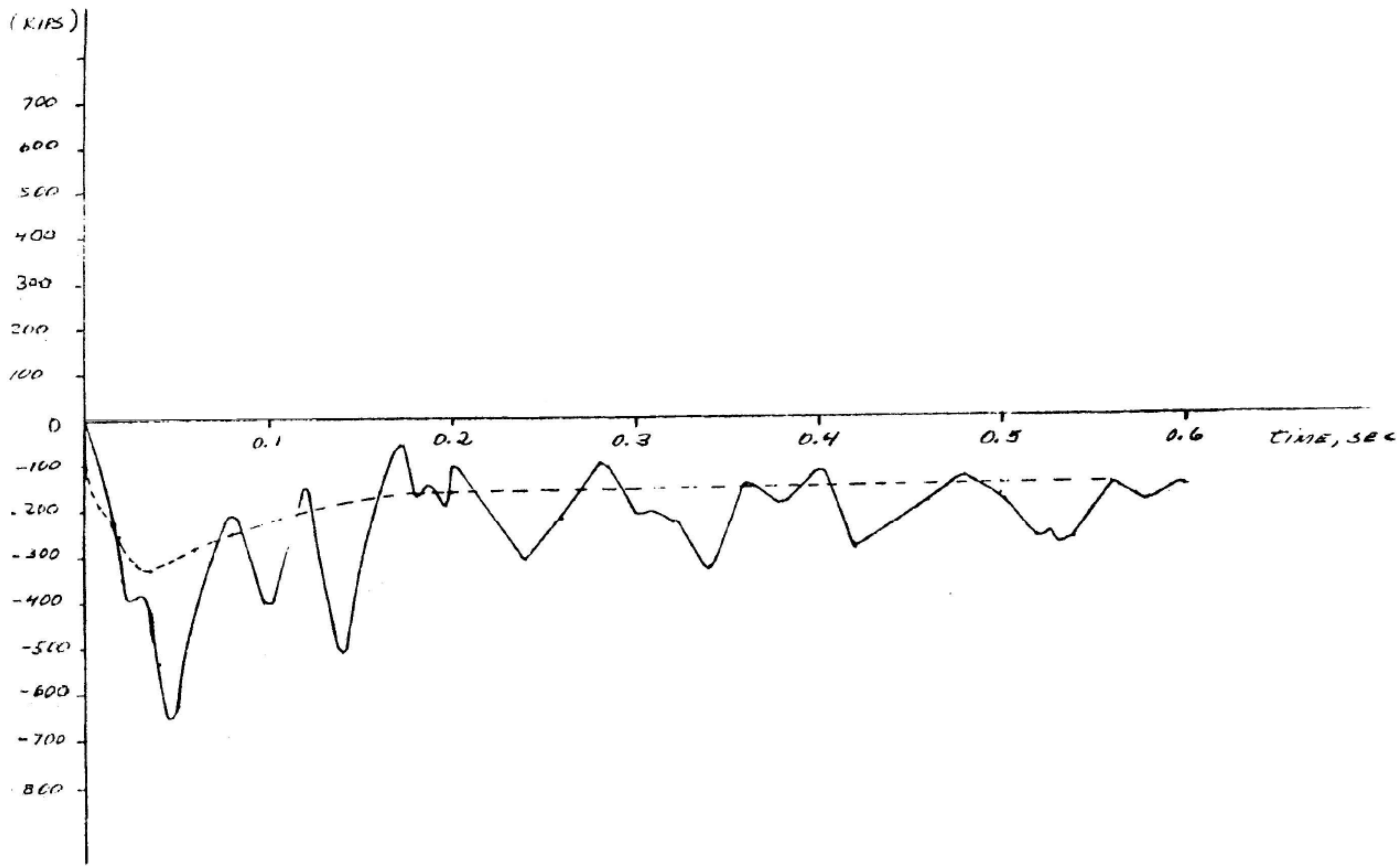
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET LINE BREAK RESULTANT MOMENT

FIGURE 6A-7

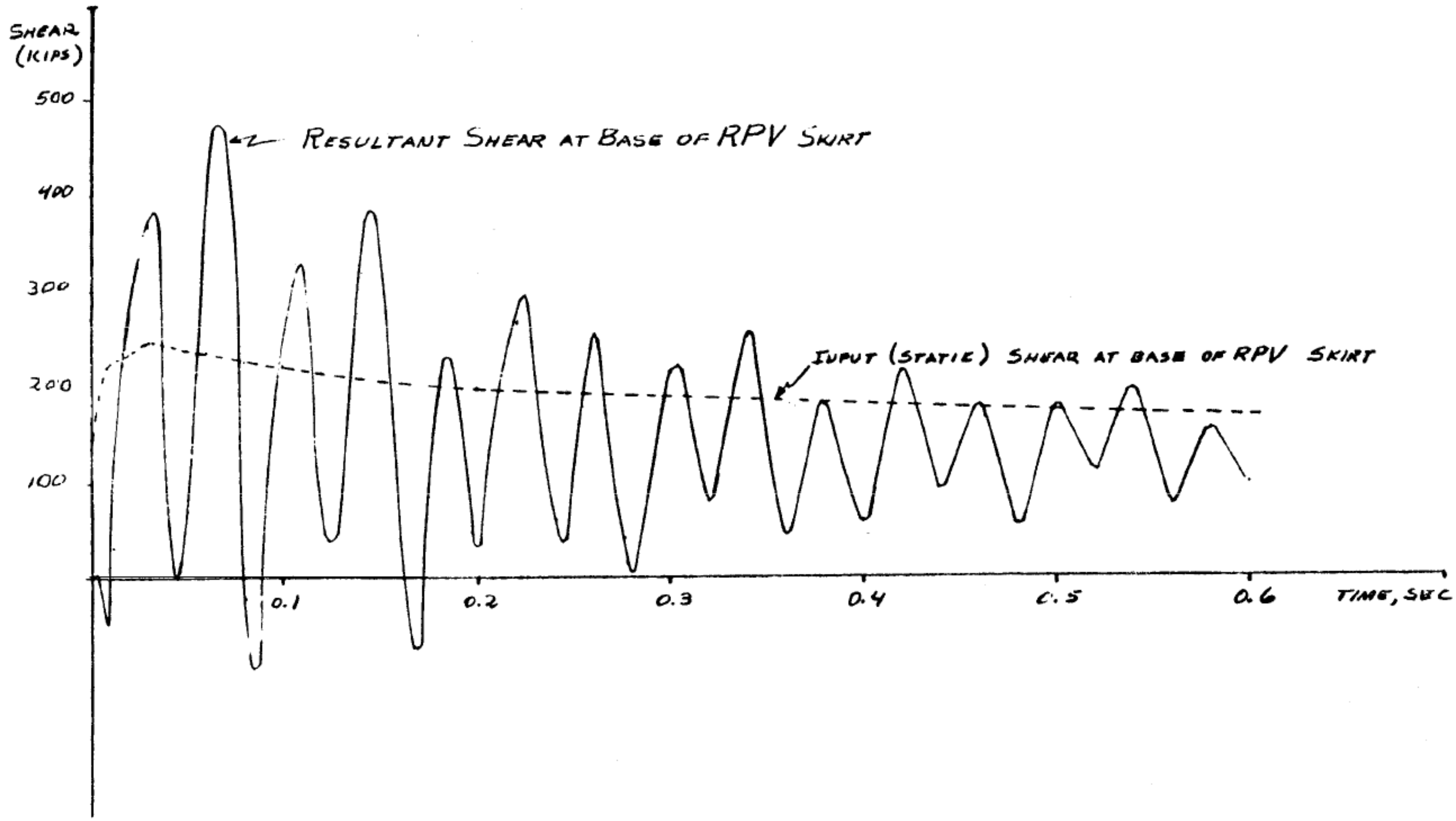


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RESPONSE TO RECIRCULATION LINE BREAK
RESULTANT FORCE AT STABILIZER SPRING

FIGURE 6A-8

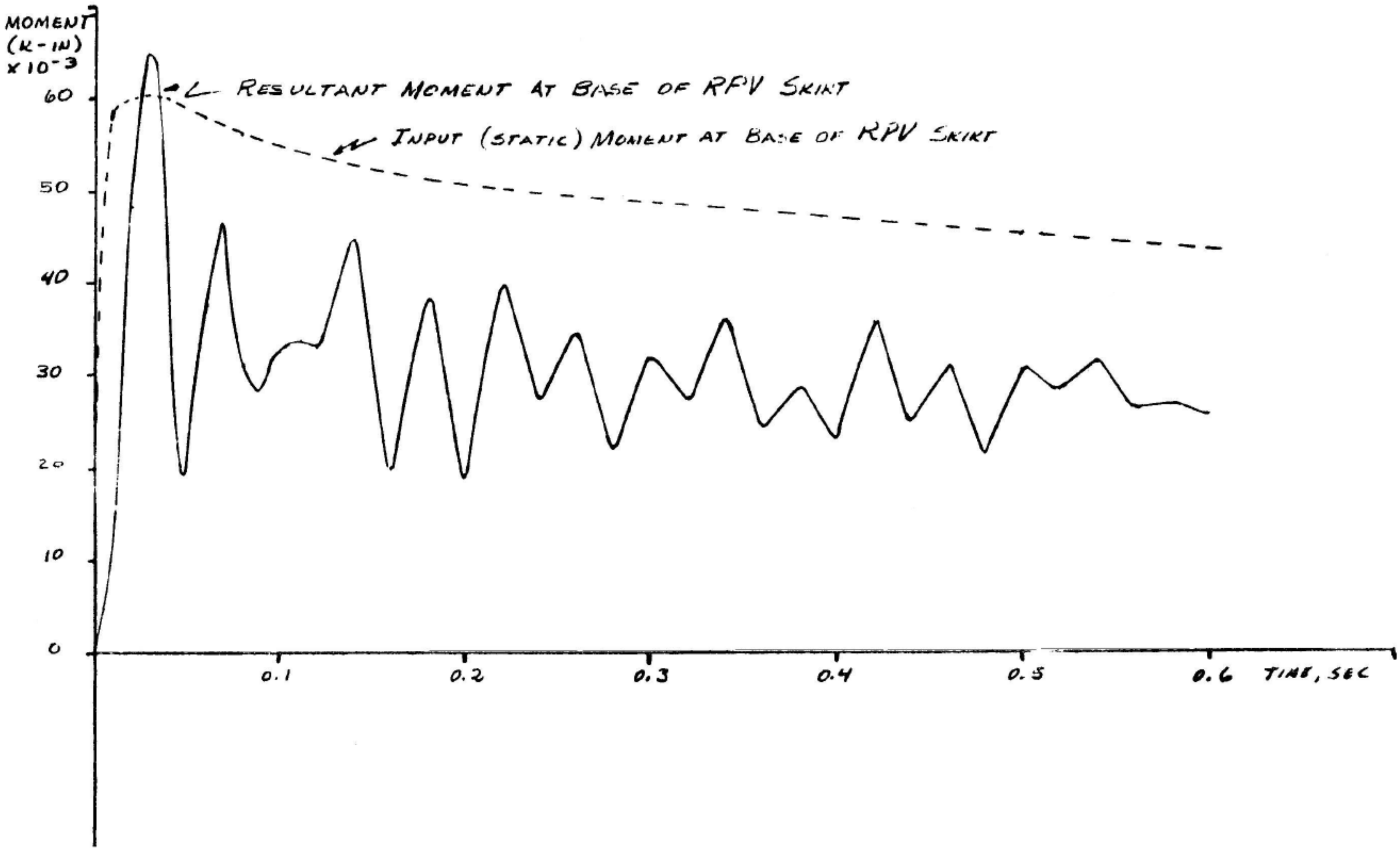


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK RESULTANT SHEAR

FIGURE 6A-9



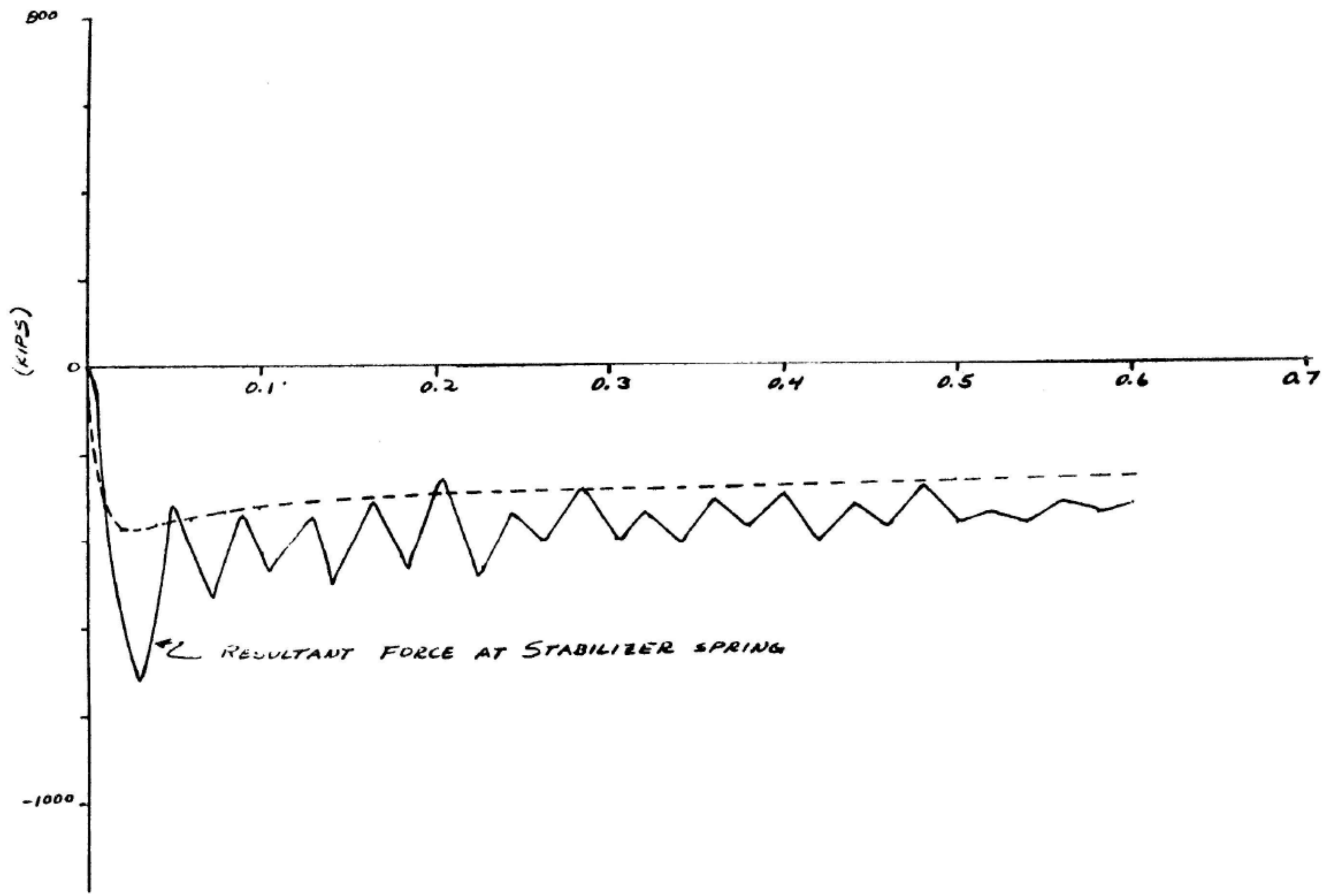
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK RESULTANT MOMENT

FIGURE 6A-10



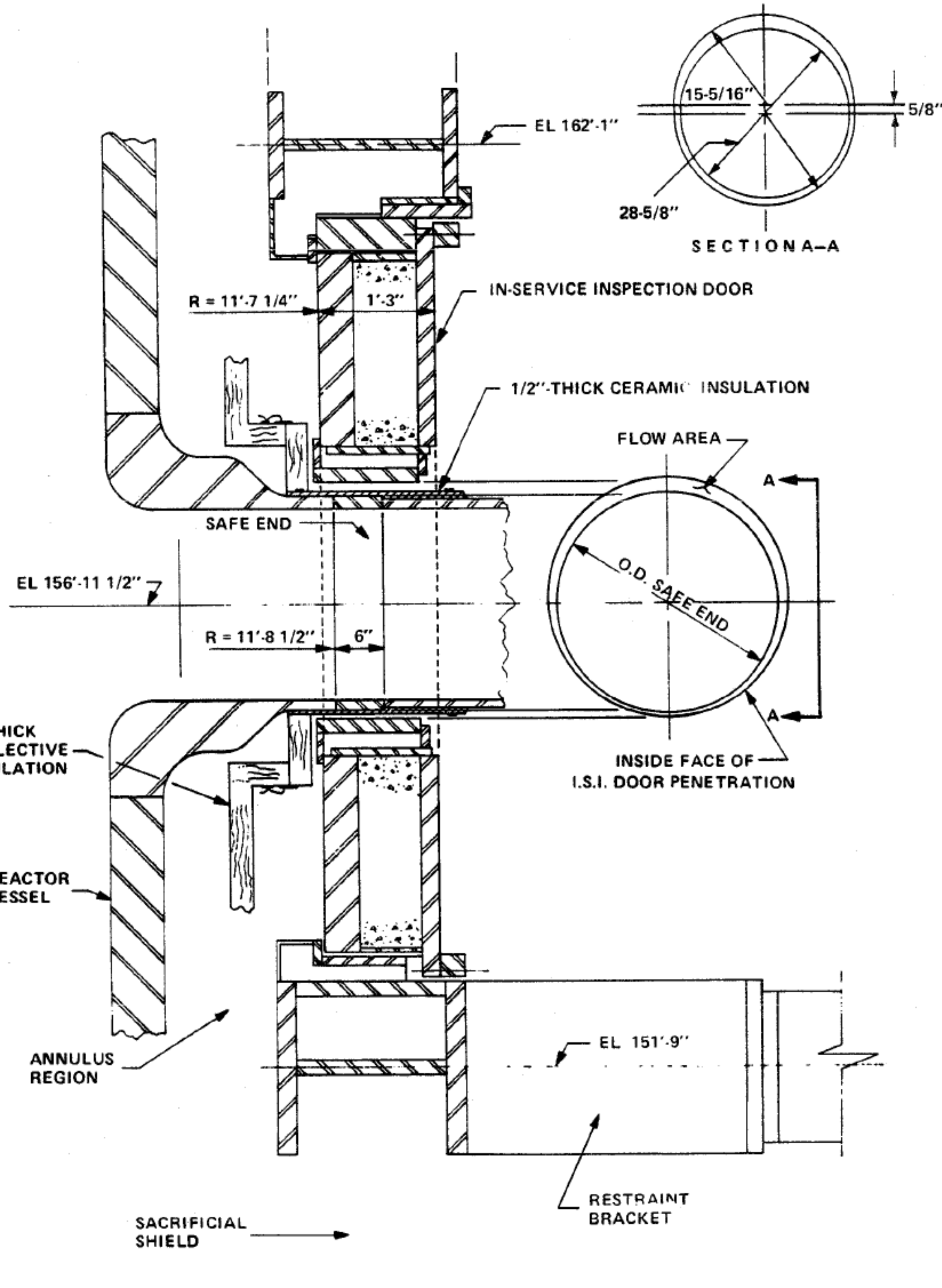
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK RESULTANT FORCE

FIGURE 6A-11



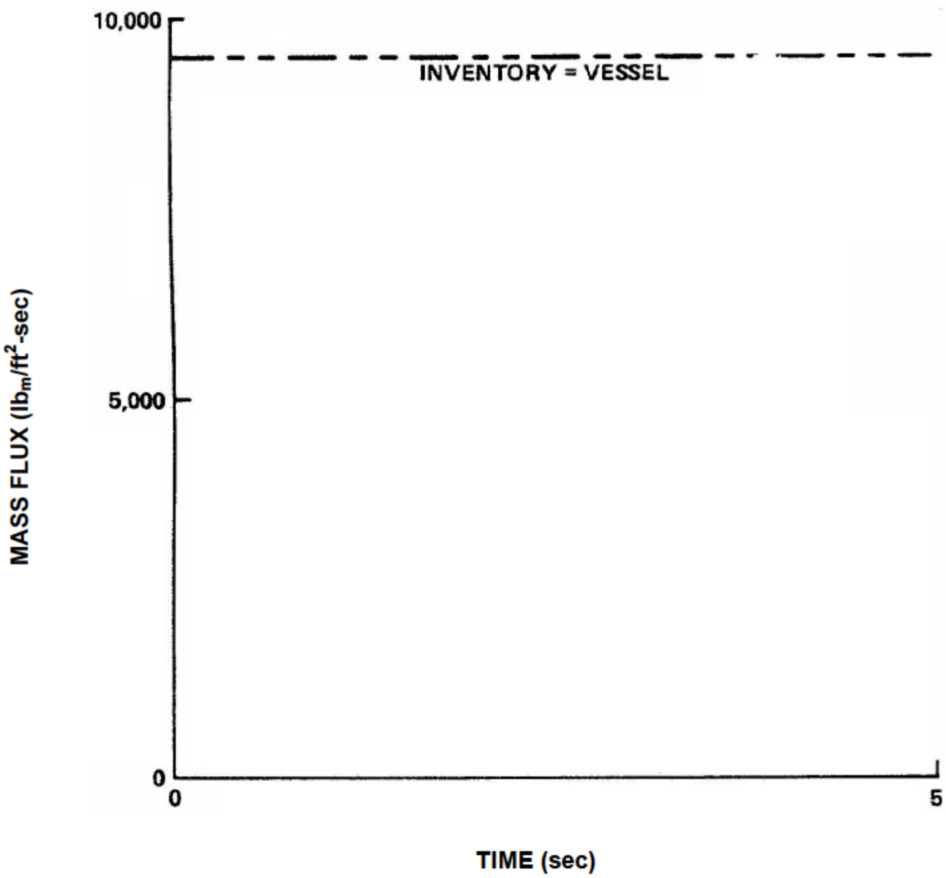
REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET NOZZLE CONFIGURATION

FIGURE 6A-12

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)	9500	9500



The increase in mass and energy releases for the recirculation outlet line break was evaluated for extended power uprate (EPU) at a power level of 2763 MWt. The results of the original analysis remained bounding.(12) Thermal power optimization (2804 MWt) did not have any impact on mass and energy releases evaluated for EPU.(13) The evaluation for reactor operating pressure increase(14) concluded that the small increase in mass and energy releases due to increase in reactor operating pressure will have no significant impact on the results of the existing analysis.

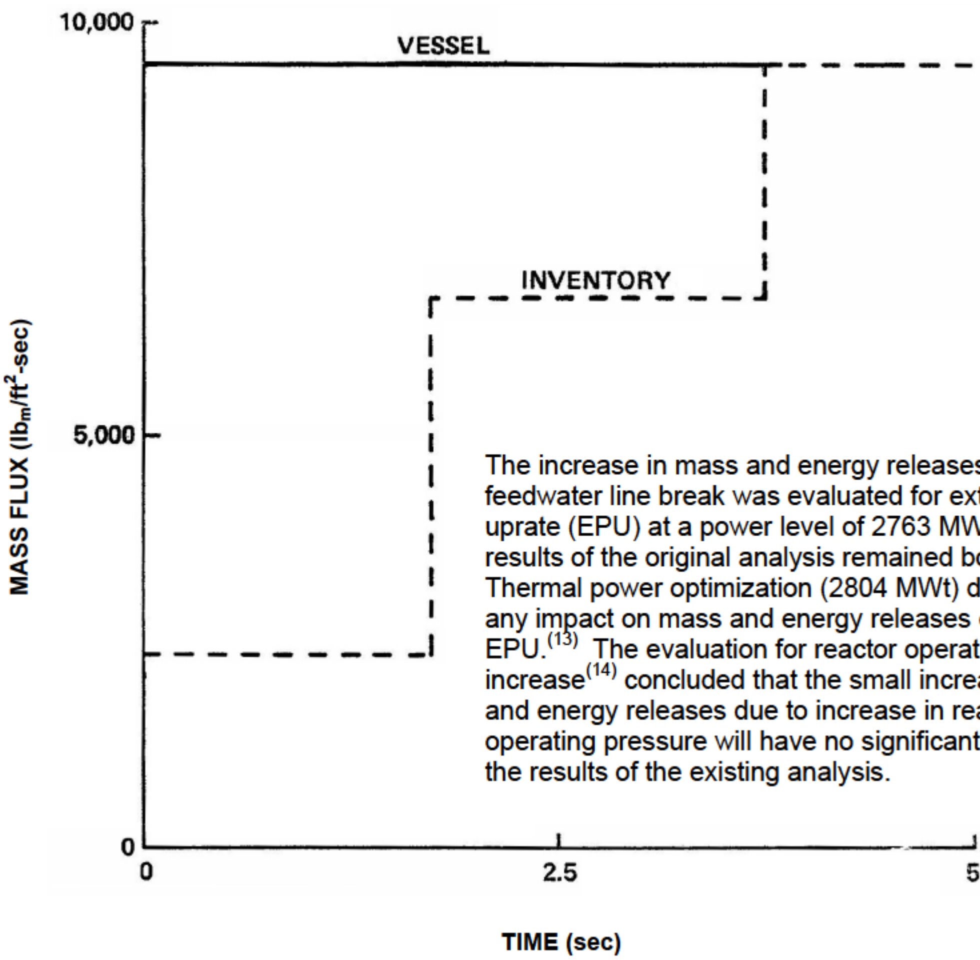
REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
RECIRCULATION OUTLET

FIGURE 6A-13

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)		
0 ≤ t ≤ 1.57 sec.	2360	9500
0.57 < t ≤ 3.76 sec.	6650	9500
3.76 < t ≤ 5.0 sec.	9500	9500



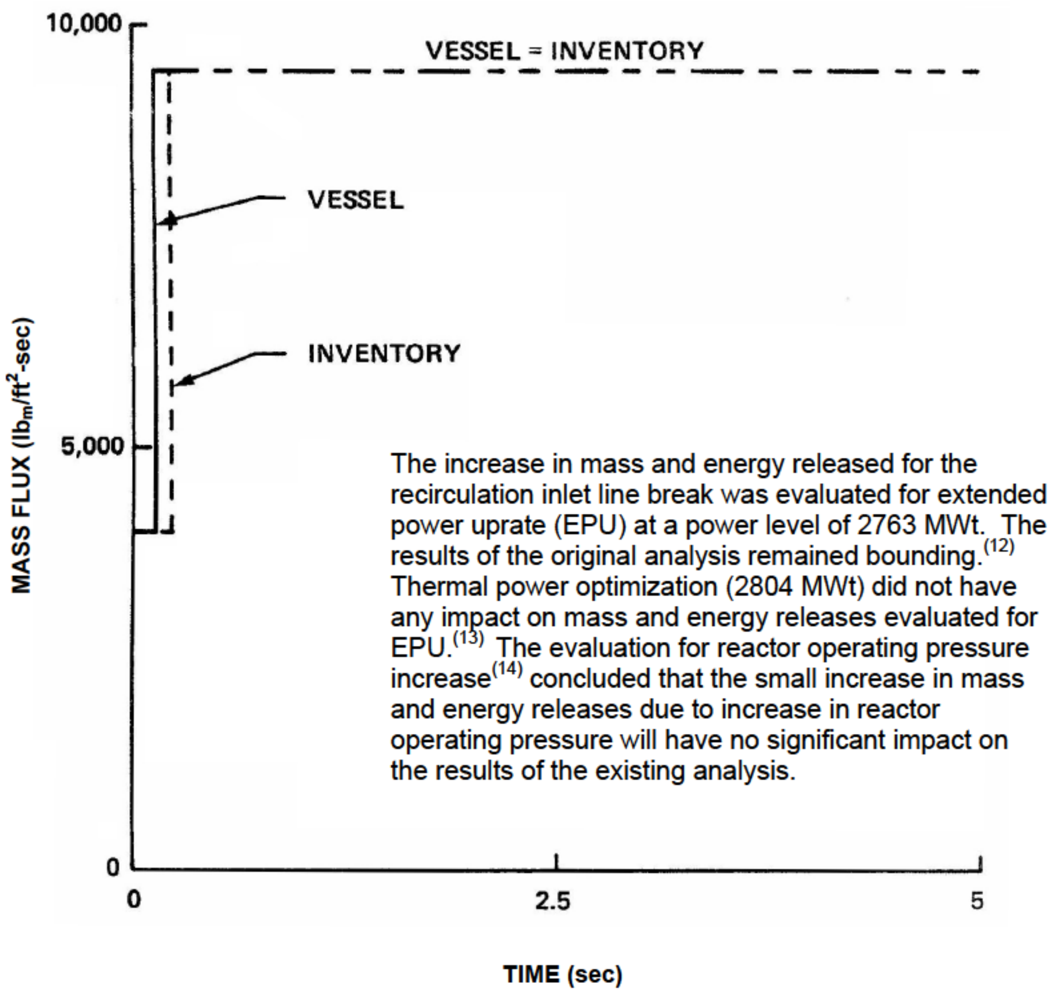
The increase in mass and energy releases for the feedwater line break was evaluated for extended power uprate (EPU) at a power level of 2763 MWt. The results of the original analysis remained bounding.(12) Thermal power optimization (2804 MWt) did not have any impact on mass and energy releases evaluated for EPU.(13) The evaluation for reactor operating pressure increase(14) concluded that the small increase in mass and energy releases due to increase in reactor operating pressure will have no significant impact on the results of the existing analysis.

REV 22 9/04

MASS FLUX VS TIME
FEEDWATER UPPER AND LOWER DRYWELL

FIGURE 6A-14

MASS FLUX (lb_m/ft^2 – sec)	INVEN.	VESSEL
$0 \leq t \leq 0.132$	4000	4000
$0.132 < t \leq 0.22$	4000	9500
$0.22 < t \leq 5.0$	9500	9500



REV 22 9/04

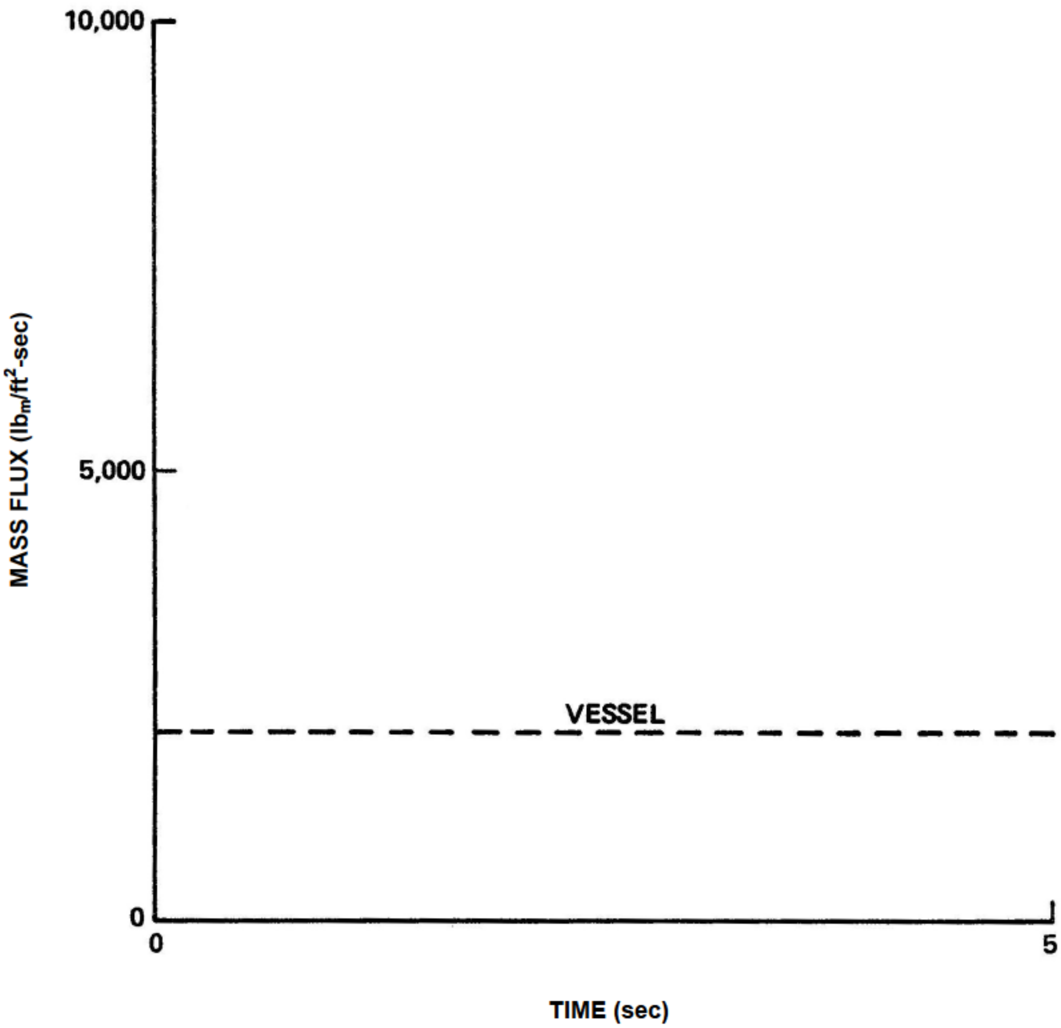
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
RECIRCULATION INLET

FIGURE 6A-15

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)	0	2100



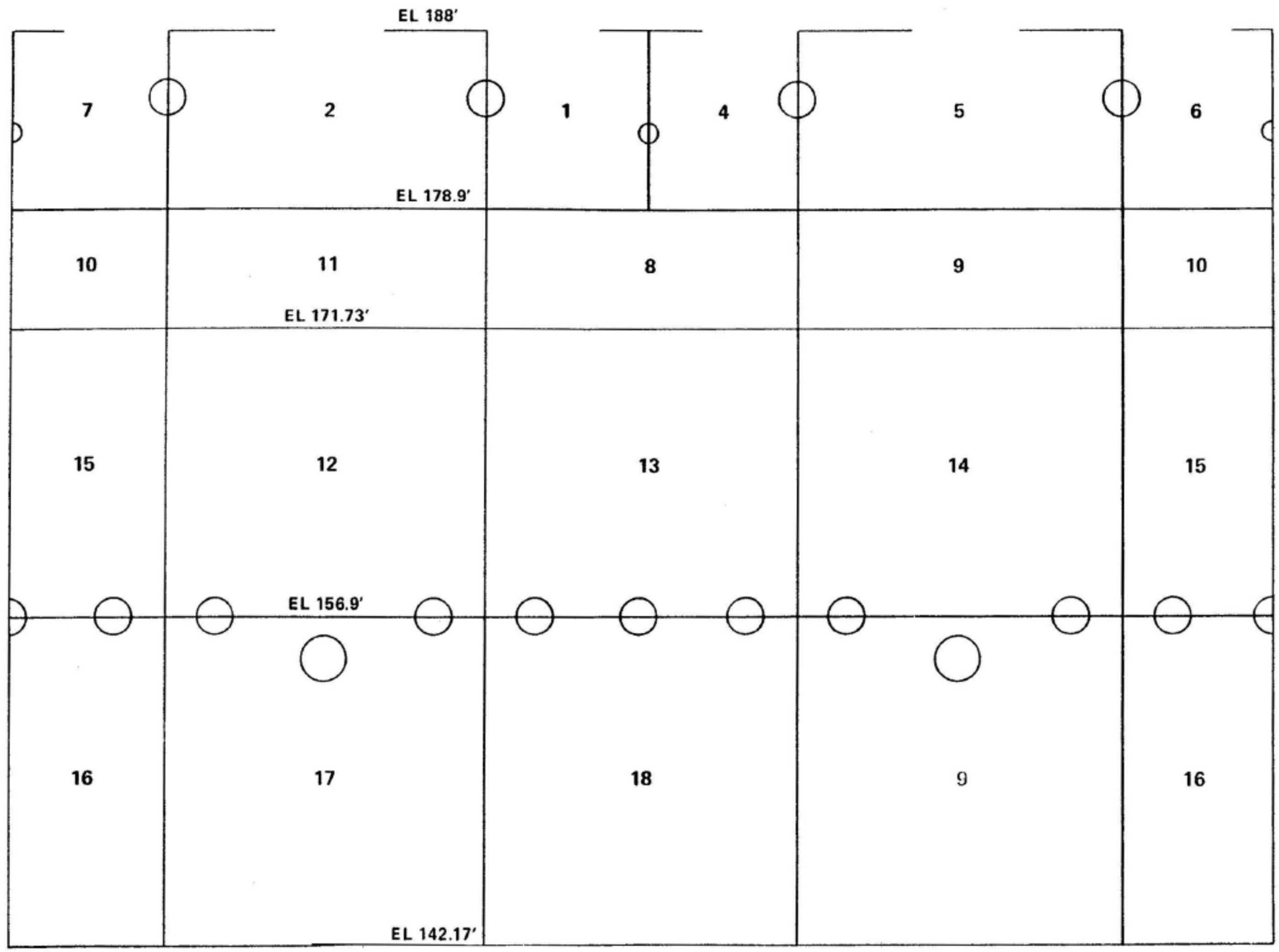
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
HEAD SPRAY

FIGURE 6A-16



3 is drywell; 20 is torus

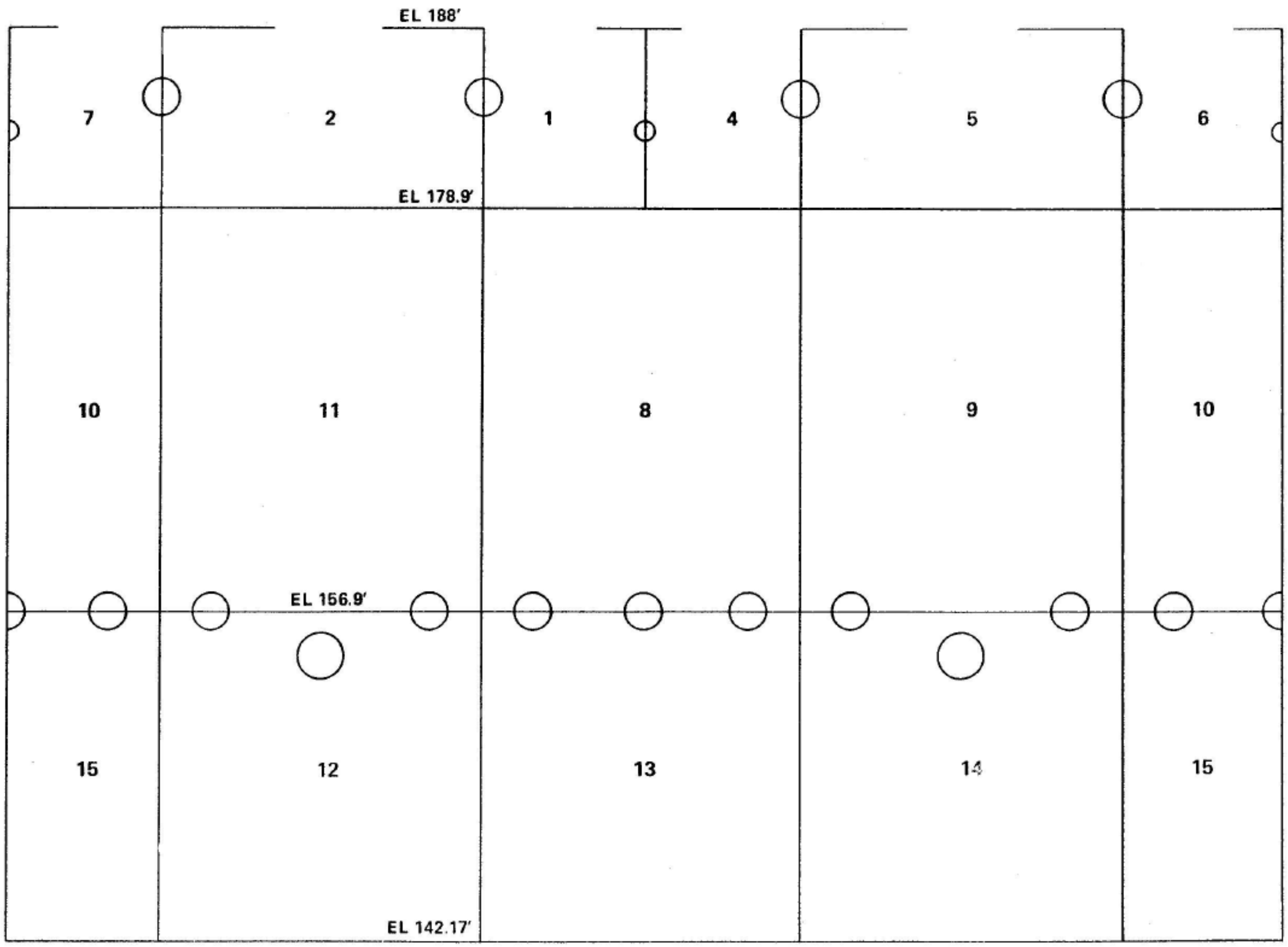
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NODE LOCATIONS FOR FEEDWATER LINE BREAK IN SHIELD ANNULUS REGION CASE A (20 NODES)

FIGURE 6A-17



3 is drywell; 16 is torus

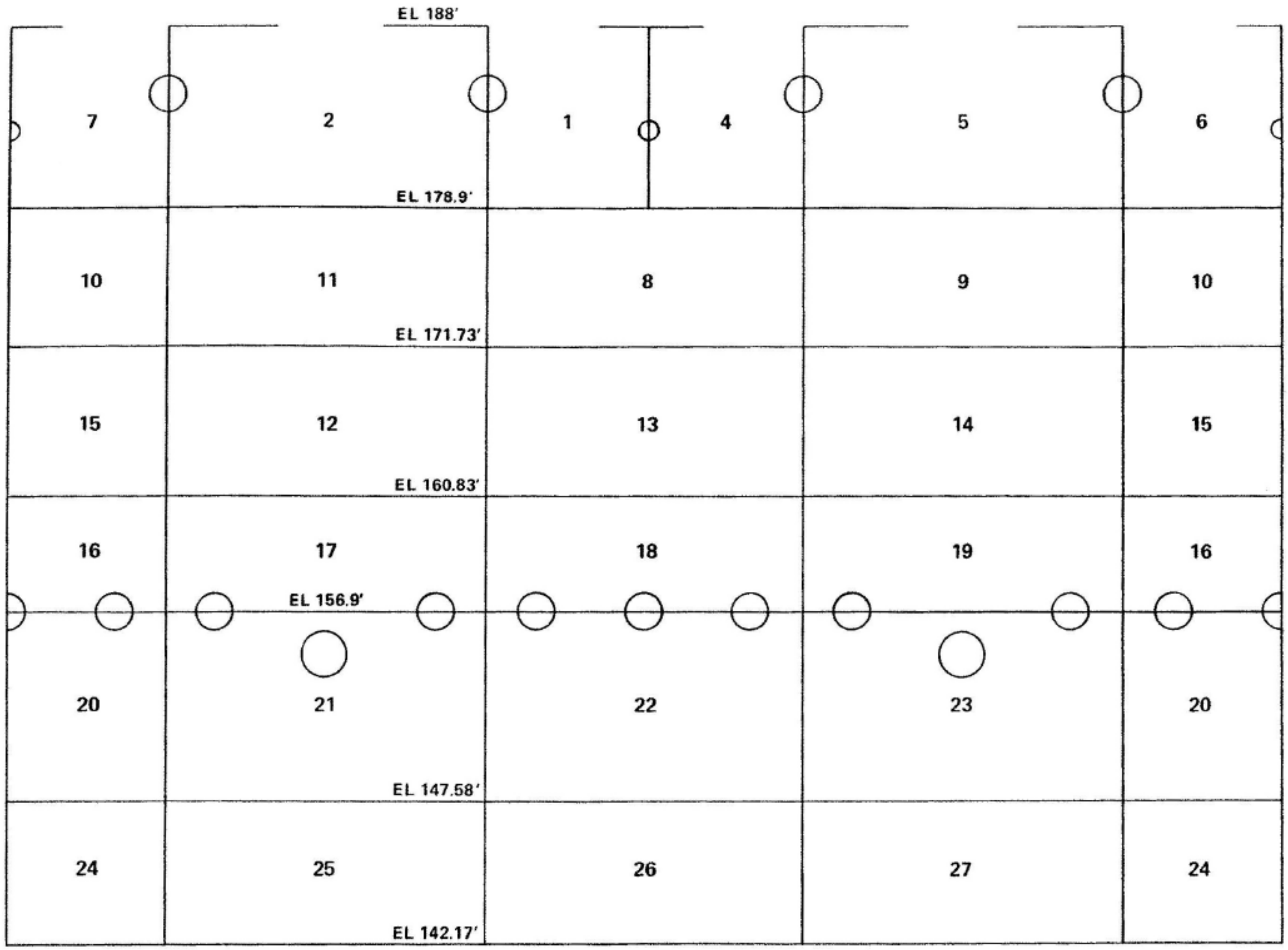
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK NODE SENSITIVITY STUDY
CASE B (16 NODES)

FIGURE 6A-18



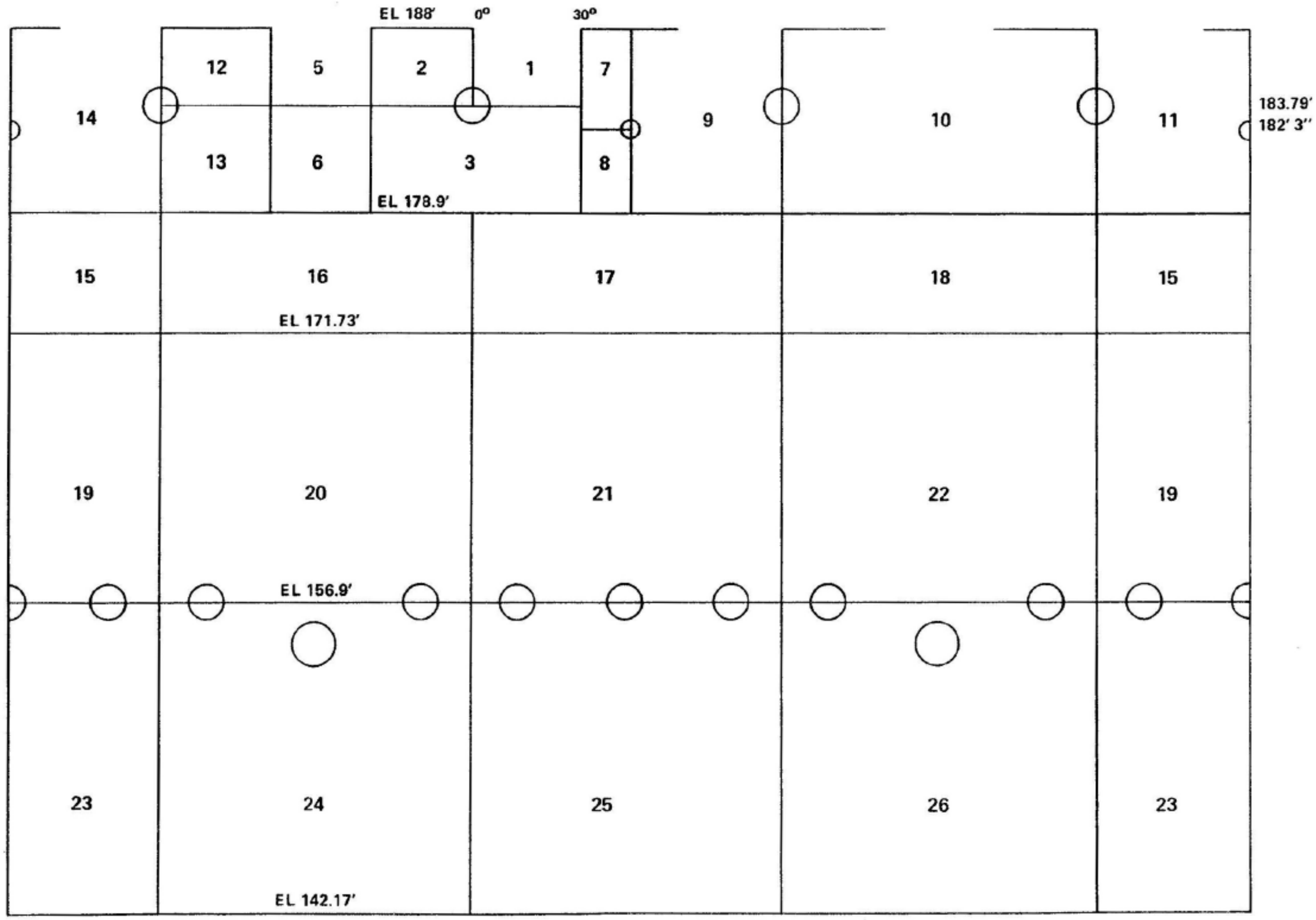
3 is drywell; 28 is torus

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK NODE SENSITIVITY STUDY
CASE C (28 NODES)

FIGURE 6A-19



4 is drywell, 27 is torus

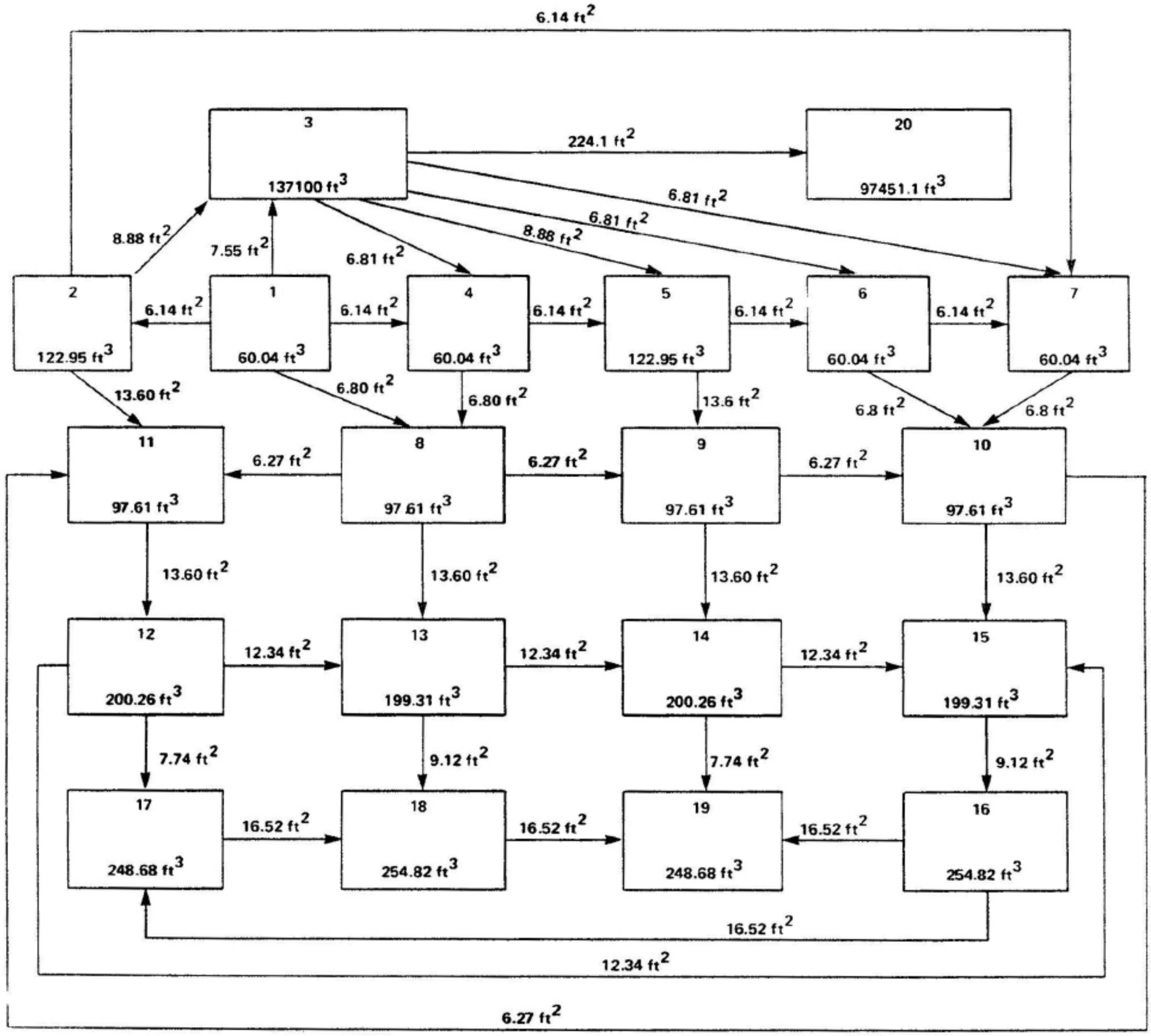
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

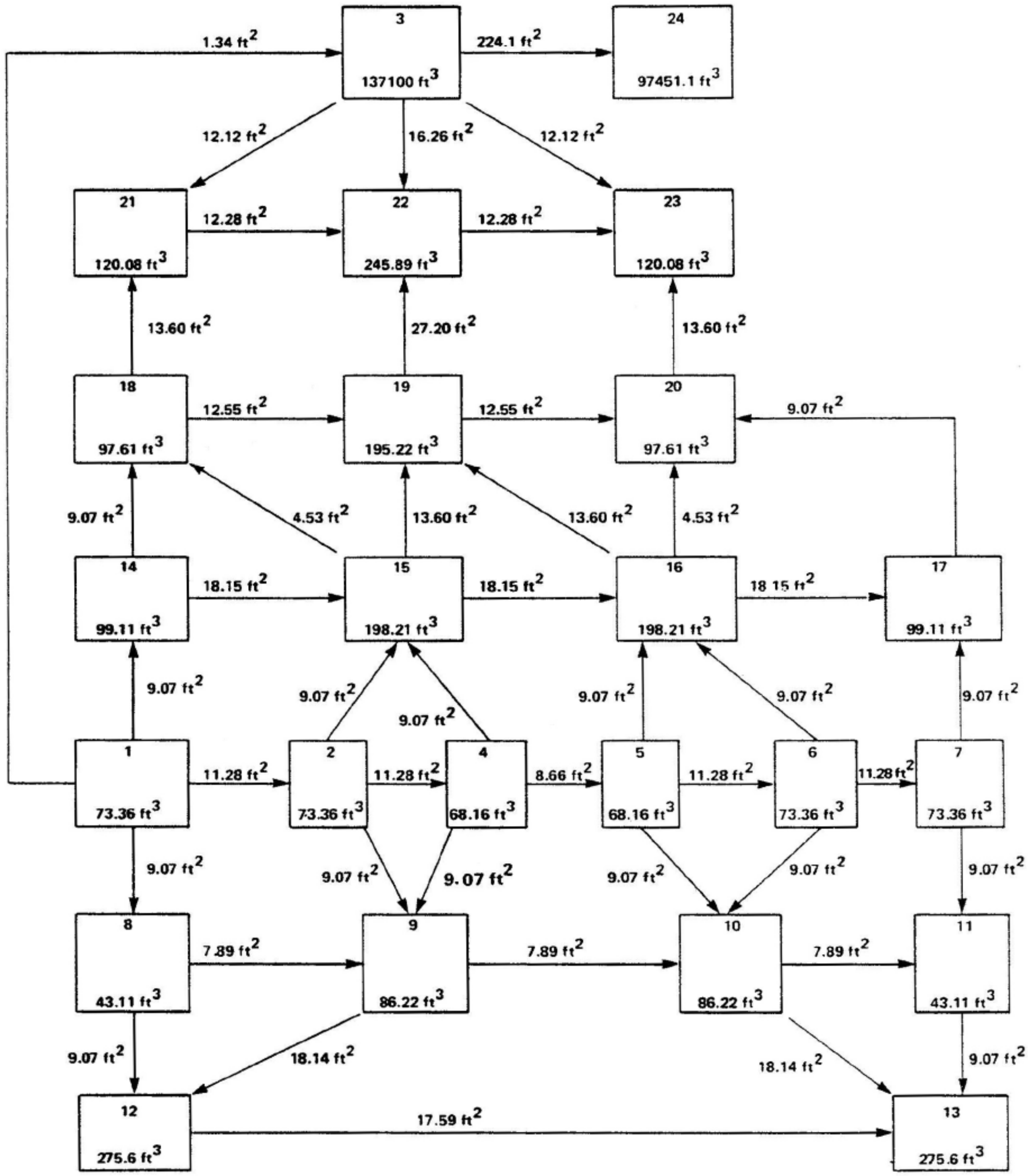
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER LINE BREAK NODE SENSITIVITY STUDY
CASE D (27 NODES)

FIGURE 6A-20

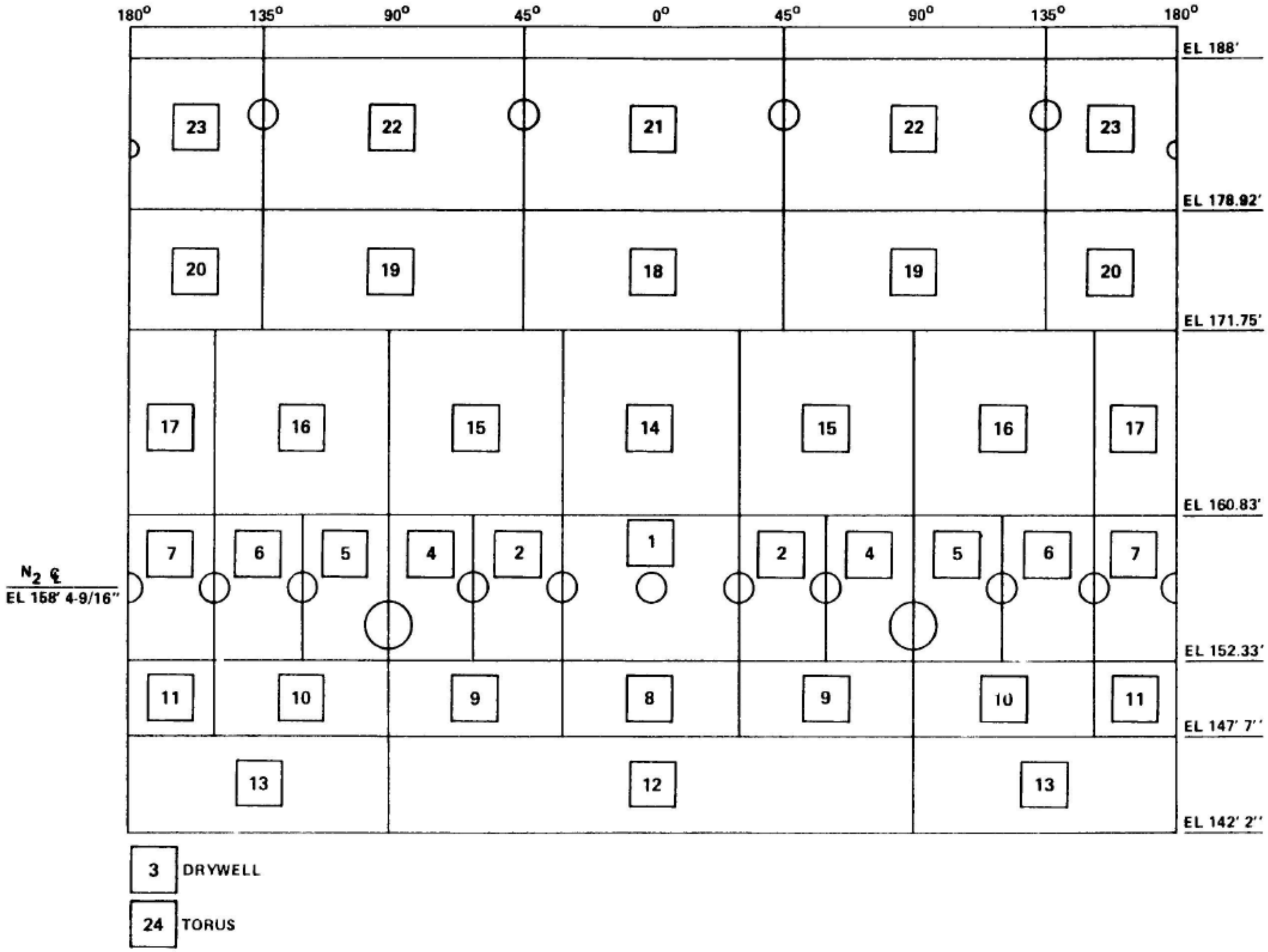

6.14 ft2
3
137100 ft3
224.1 ft2
20
97451.1 ft3
6.81 ft2
6.81 ft2
8.88 ft2
8.88 ft2
7.55 ft2
6.81 ft2
2
122.95 ft3
6.14 ft2
1
60.04 ft3
6.14 ft2
4
60.04 ft3
6.14 ft2
5
122.95 ft3
6.14 ft2
6
60.04 ft3
6.14 ft2
7
60.04 ft3
13.60 ft2
6.80 ft2
6.80 ft2
13.6 ft2
6.8 ft2
6.8 ft2
11
97.61 ft3
6.27 ft2
8
97.61 ft3
6.27 ft2
9
97.61 ft3
6.27 ft2
10
97.61 ft3
13.60 ft2
13.60 ft2
13.60 ft2
13.60 ft2
12
200.26 ft3
12.34 ft2
13
199.31 ft3
12.34 ft2
14
200.26 ft3
12.34 ft2
15
199.31 ft3
7.74 ft2
9.12 ft2
7.74 ft2
9.12 ft2
17
248.68 ft3
16.52 ft2
18
254.82 ft3
16.52 ft2
19
248.68 ft3
16.52 ft2
16
254.82 ft3
16.52 ft2
12.34 ft2
6.27 ft2

REV 19 7/01



REV 19 7/01

SOUTHERN COMPANY Energy to Serve Your World® SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	SCHEMATIC FLOW DIAGRAM FOR RECIRCULATION INLET LINE BREAK IN SHIELD ANNULUS REGION
	FIGURE 6A-22



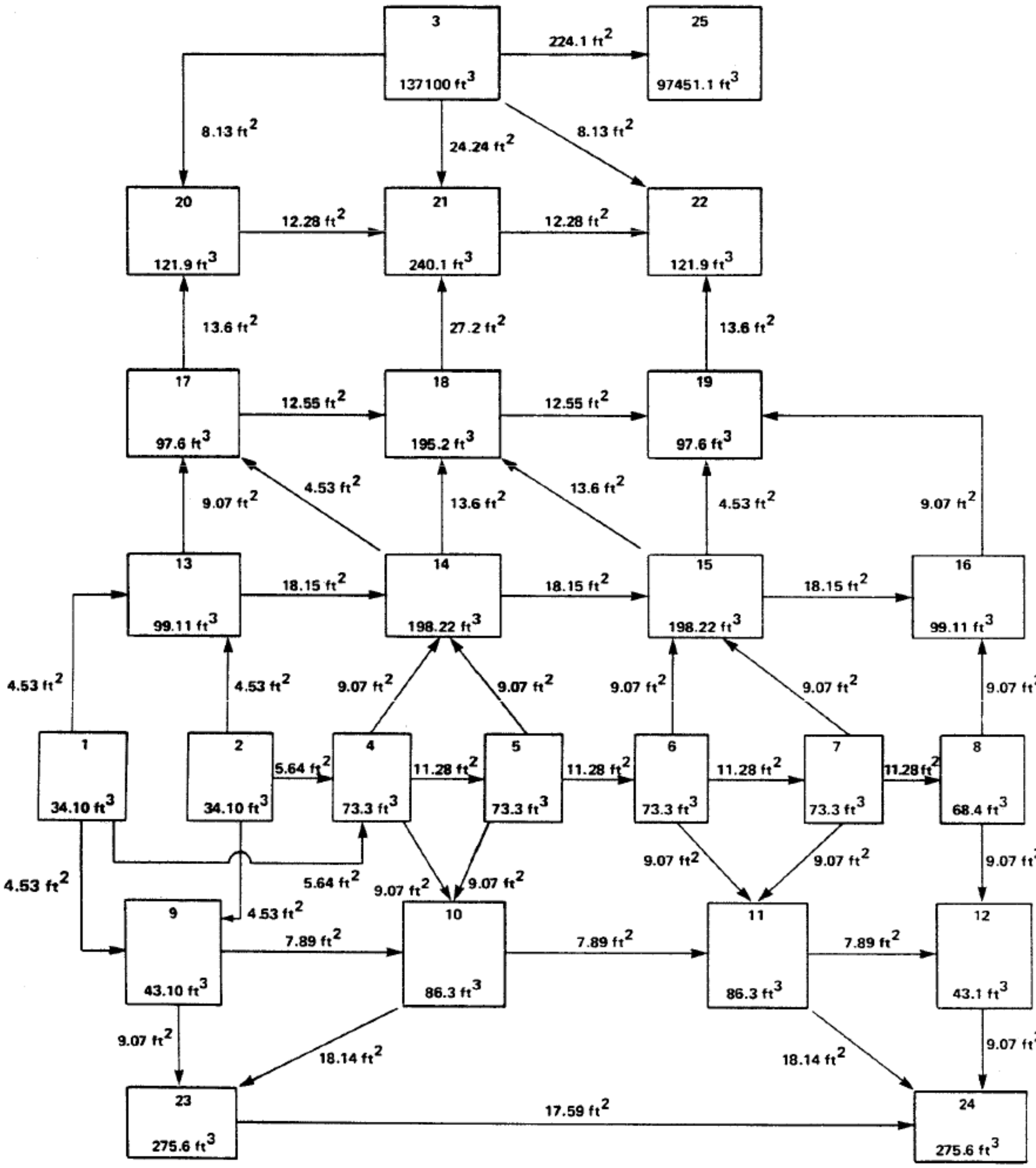
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NODE LOCATIONS FOR RECIRCULATION INLET LINE BREAK IN SHIELD ANNULUS REGION

FIGURE 6A-23



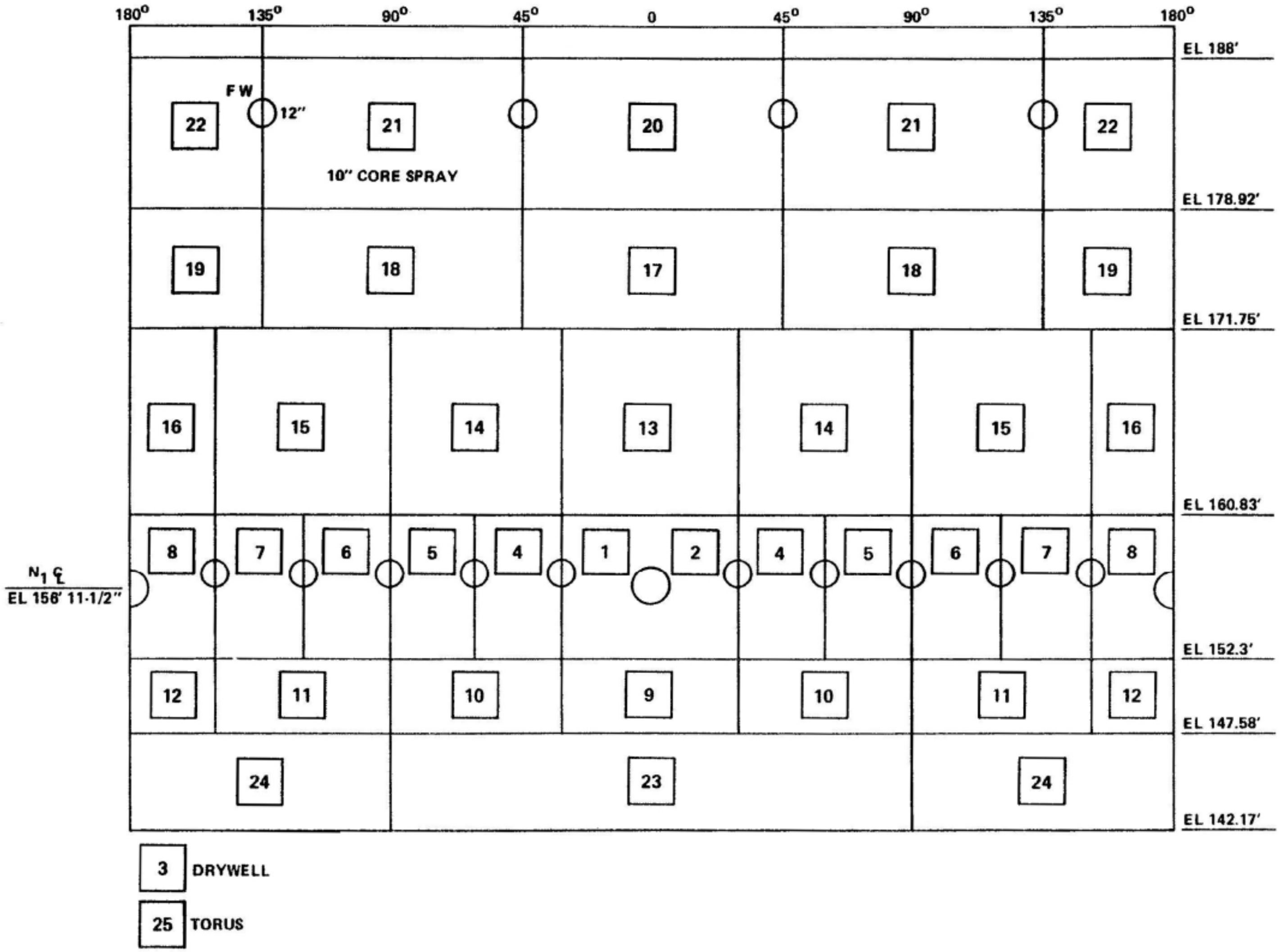
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC FLOW DIAGRAM FOR
RECIRCULATION OUTLET LINE BREAK IN
SHIELD ANNULUS REGION

FIGURE 6A-24



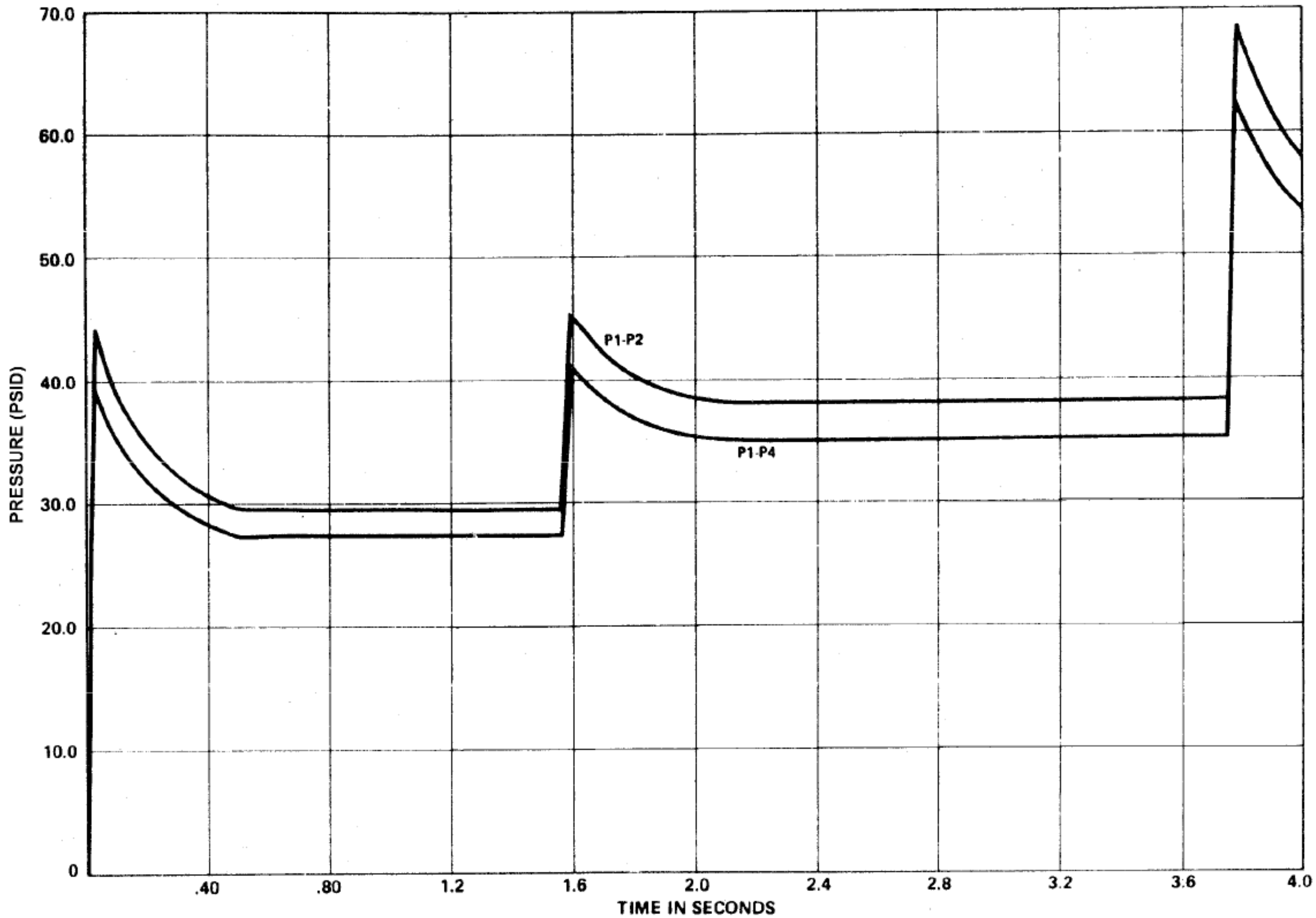
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NODE LOCATIONS FOR RECIRCULATION OUTLET LINE BREAK IN SHIELD ANNULUS REGION

FIGURE 6A-25



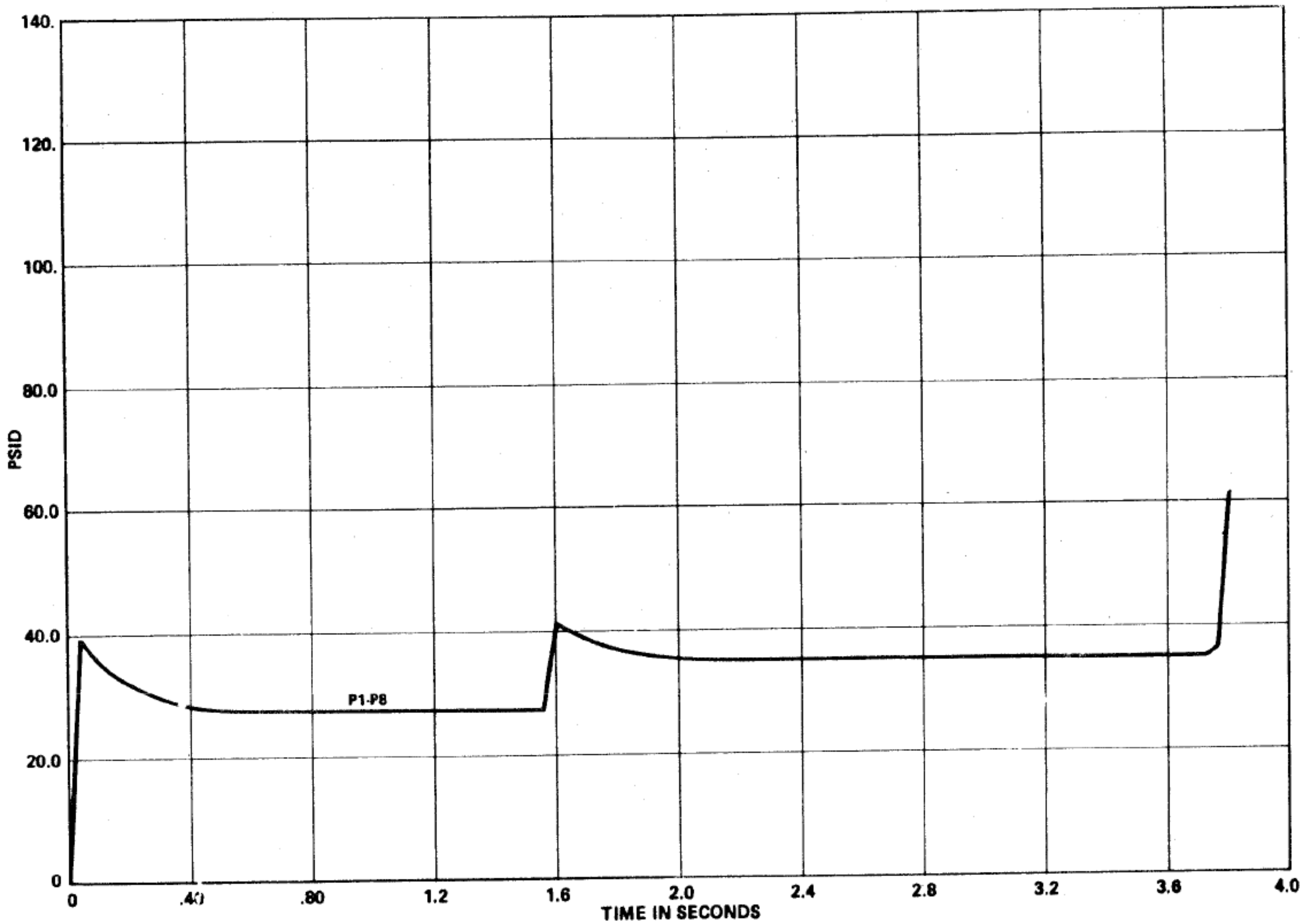
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P1-P2, P1-P4 FOR
H-2 FEEDWATER BREAK

FIGURE 6A-26



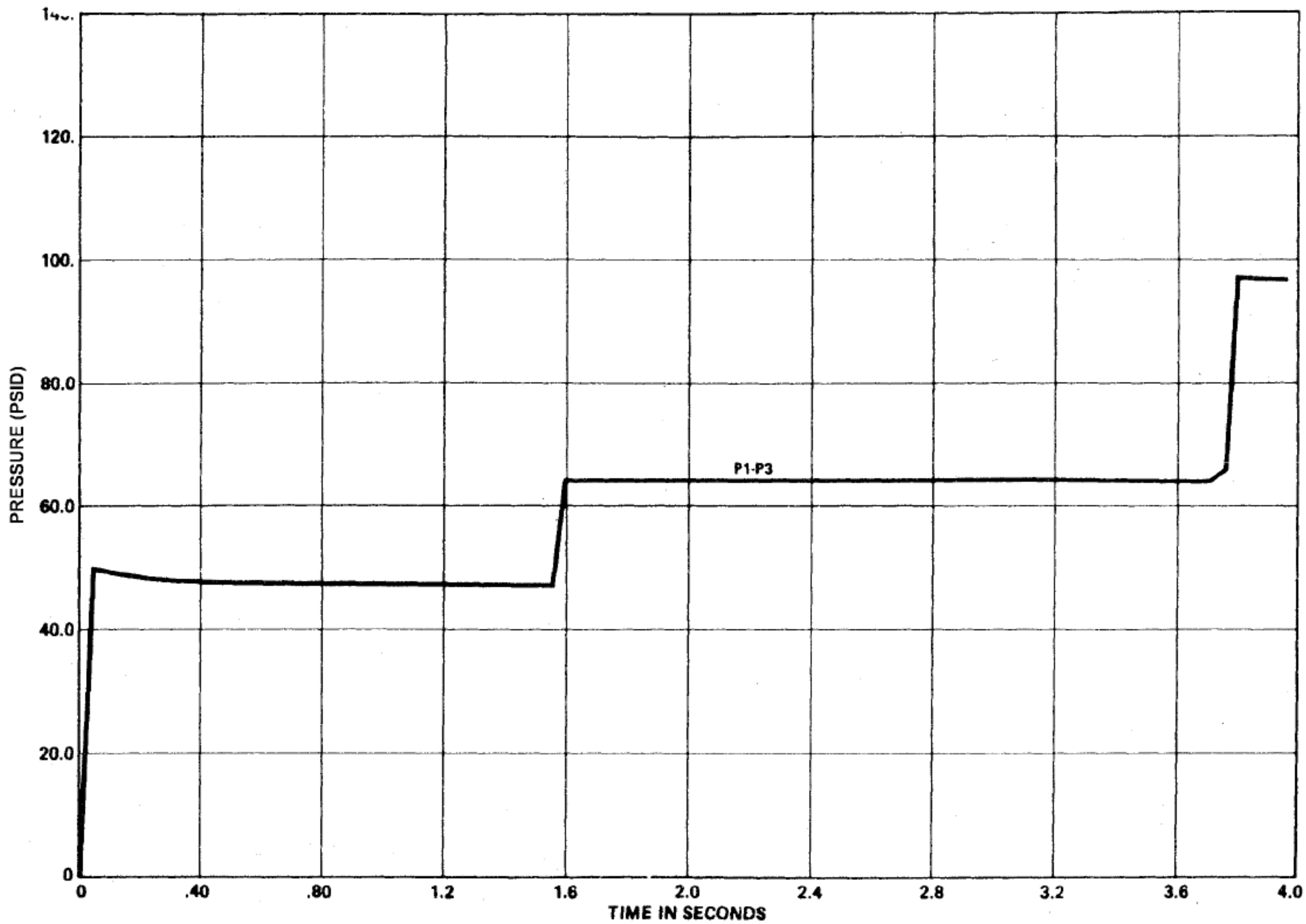
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P1-P8 FOR H-2 FEEDWATER BREAK

FIGURE 6A-27

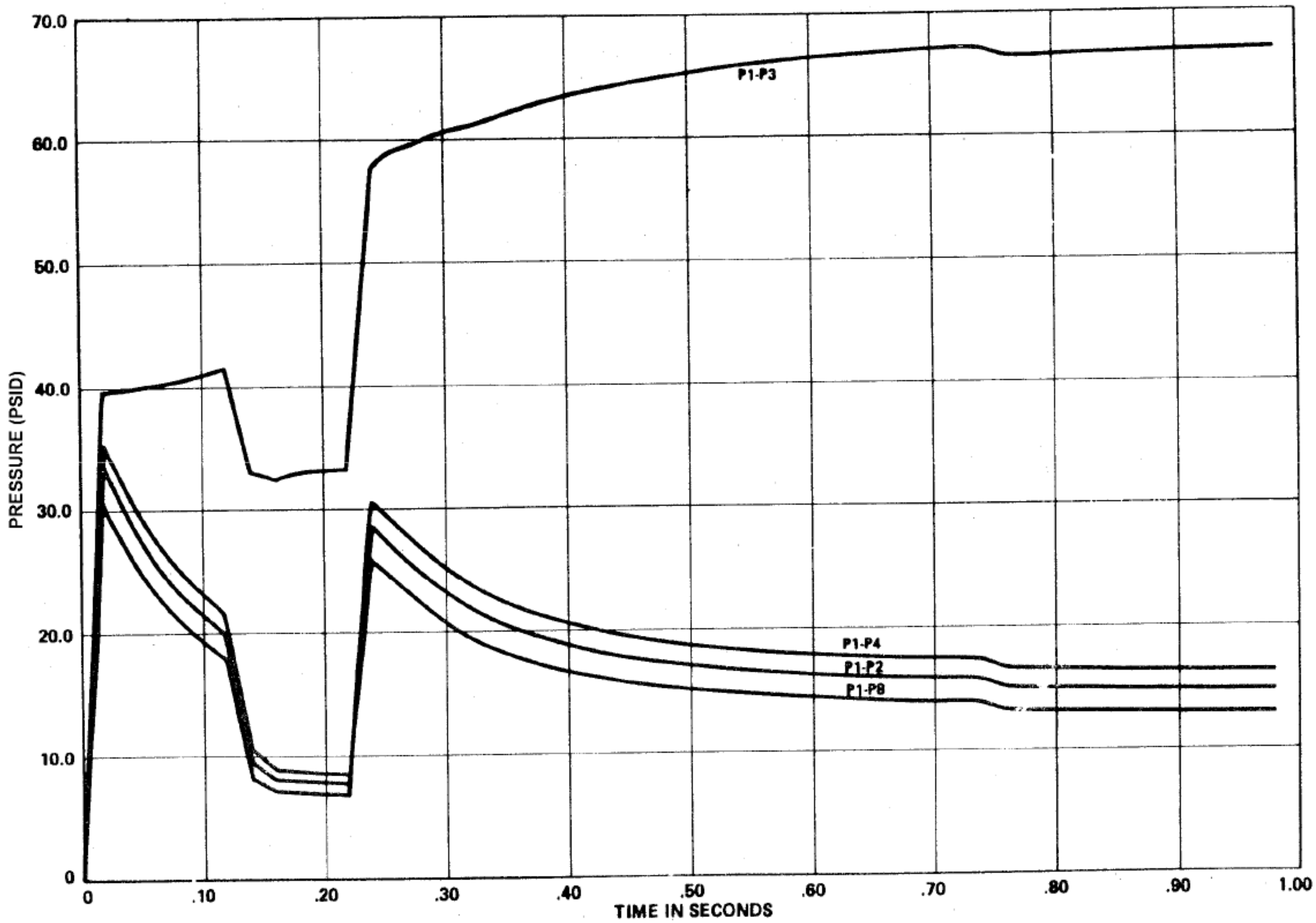


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P1-P3 FOR H-2 FEEDWATER BREAK

FIGURE 6A-28



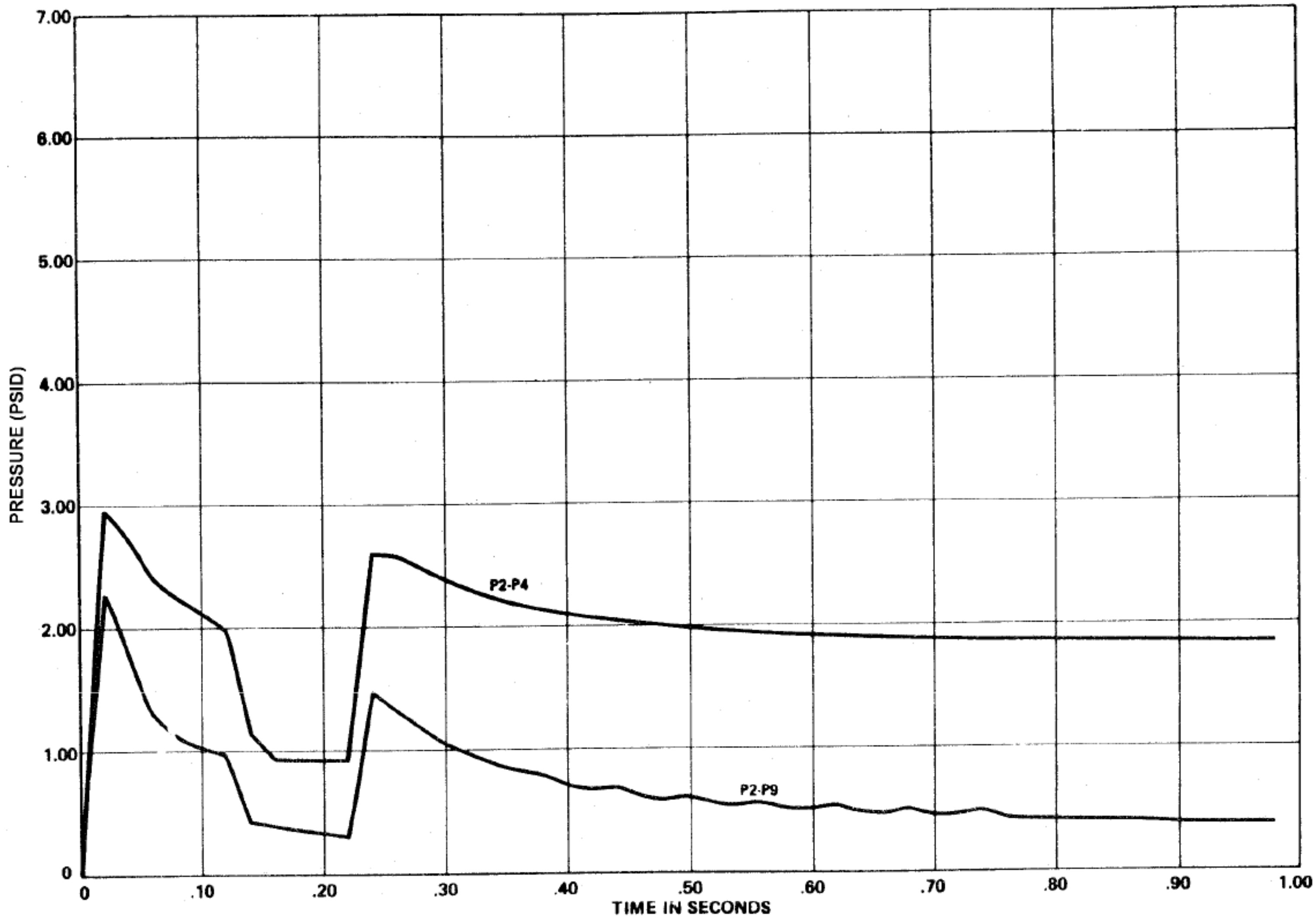
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P1-P2, P1-P3, P1-P4, P1-P8 FOR H-2 RECIRCULATION INLET BREAK

FIGURE 6A-29



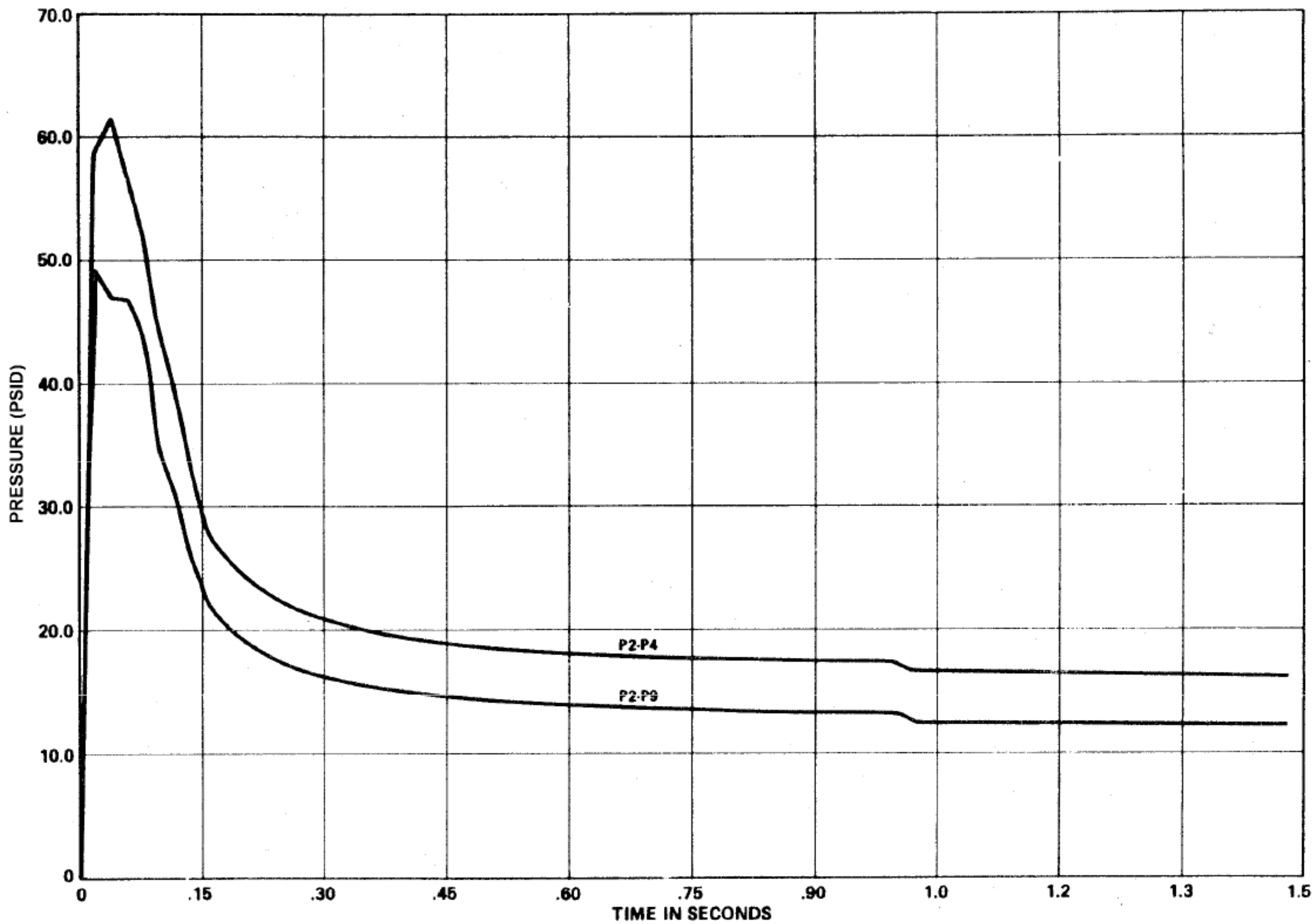
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P2-P4, P2-P9 FOR
H-2 RECIRCULATION INLET BREAK

FIGURE 6A-30



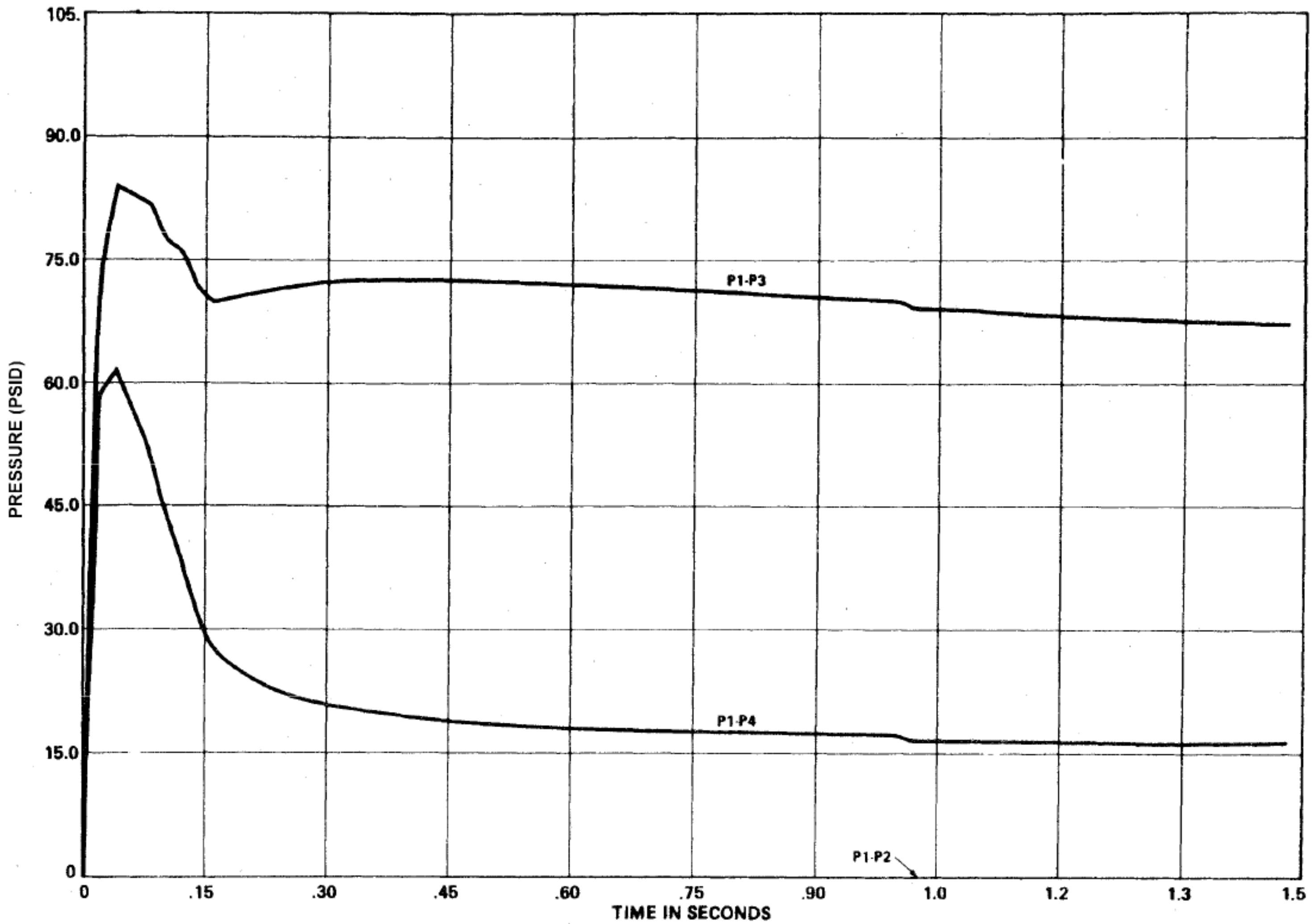
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P2-P4, P2-P9 FOR
H-2 RECIRCULATION OUTLET BREAK

FIGURE 6A-31



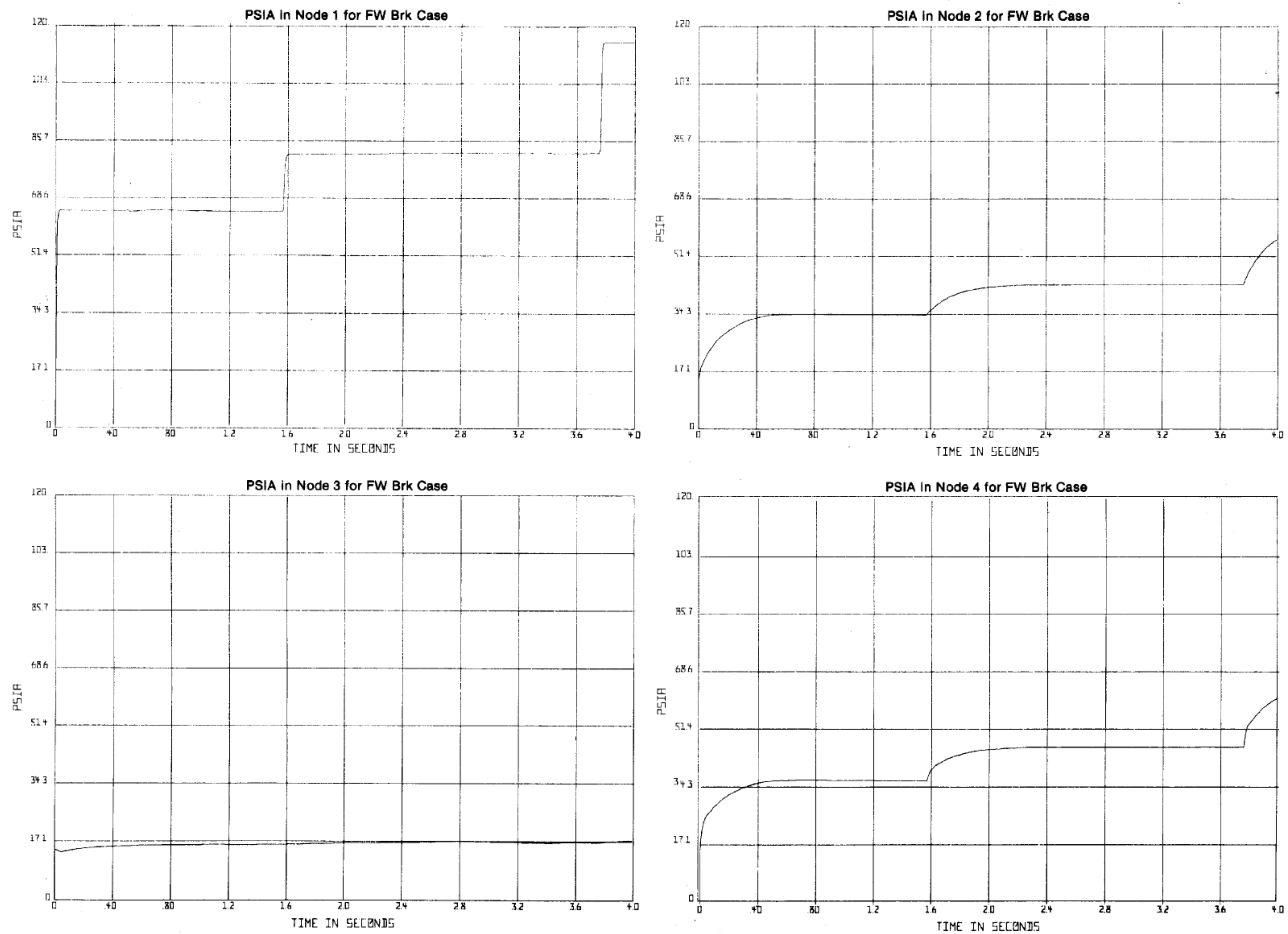
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ΔP BETWEEN NODES P1-P2, P1-P3, P1-P4 FOR
H-2 RECIRCULATION OUTLET BREAK

FIGURE 6A-32



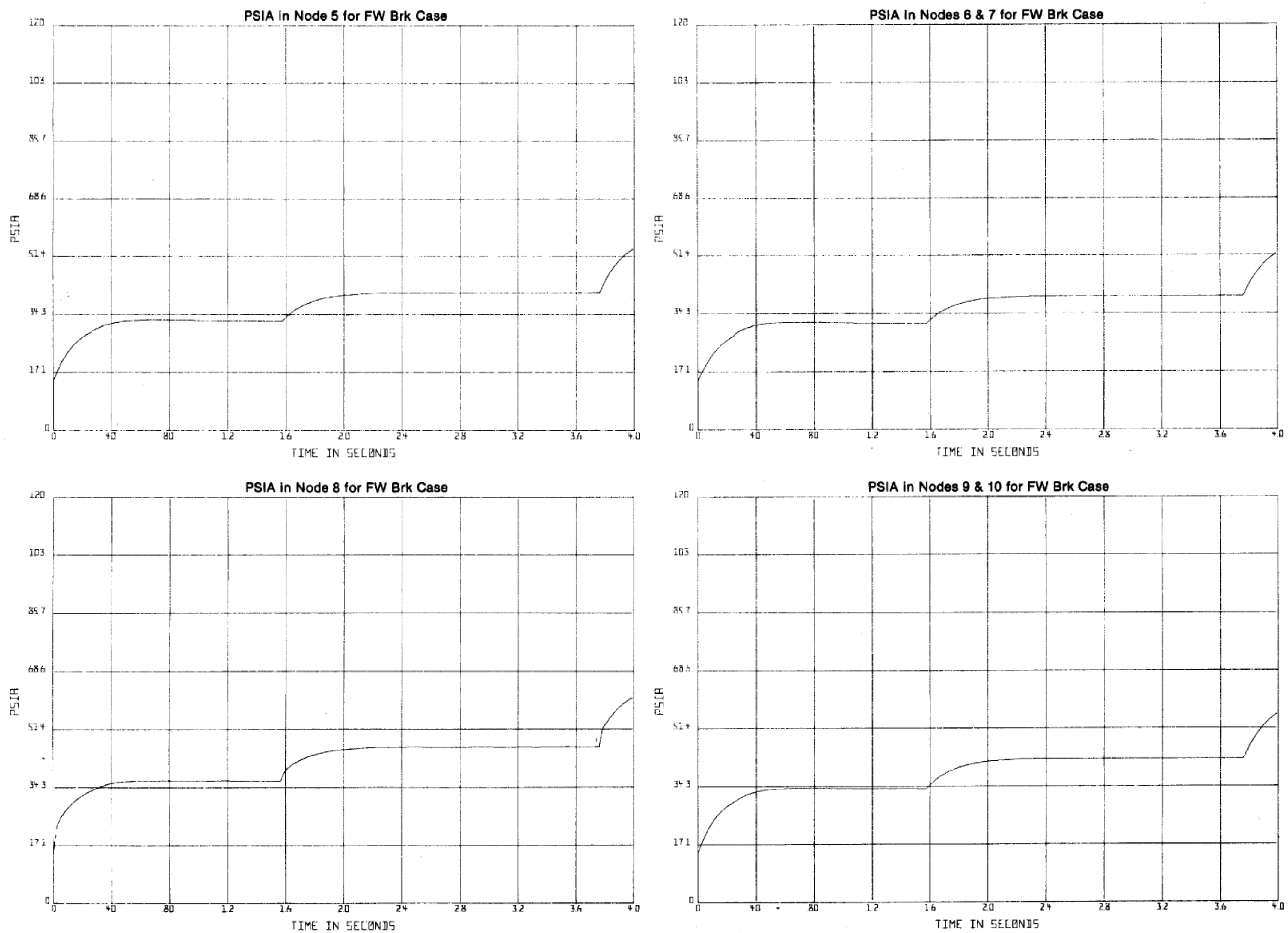
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER BREAK PRESSURE IN NODES 1, 2, 3, AND 4

FIGURE 6A-33 (SHEET 1 OF 3)



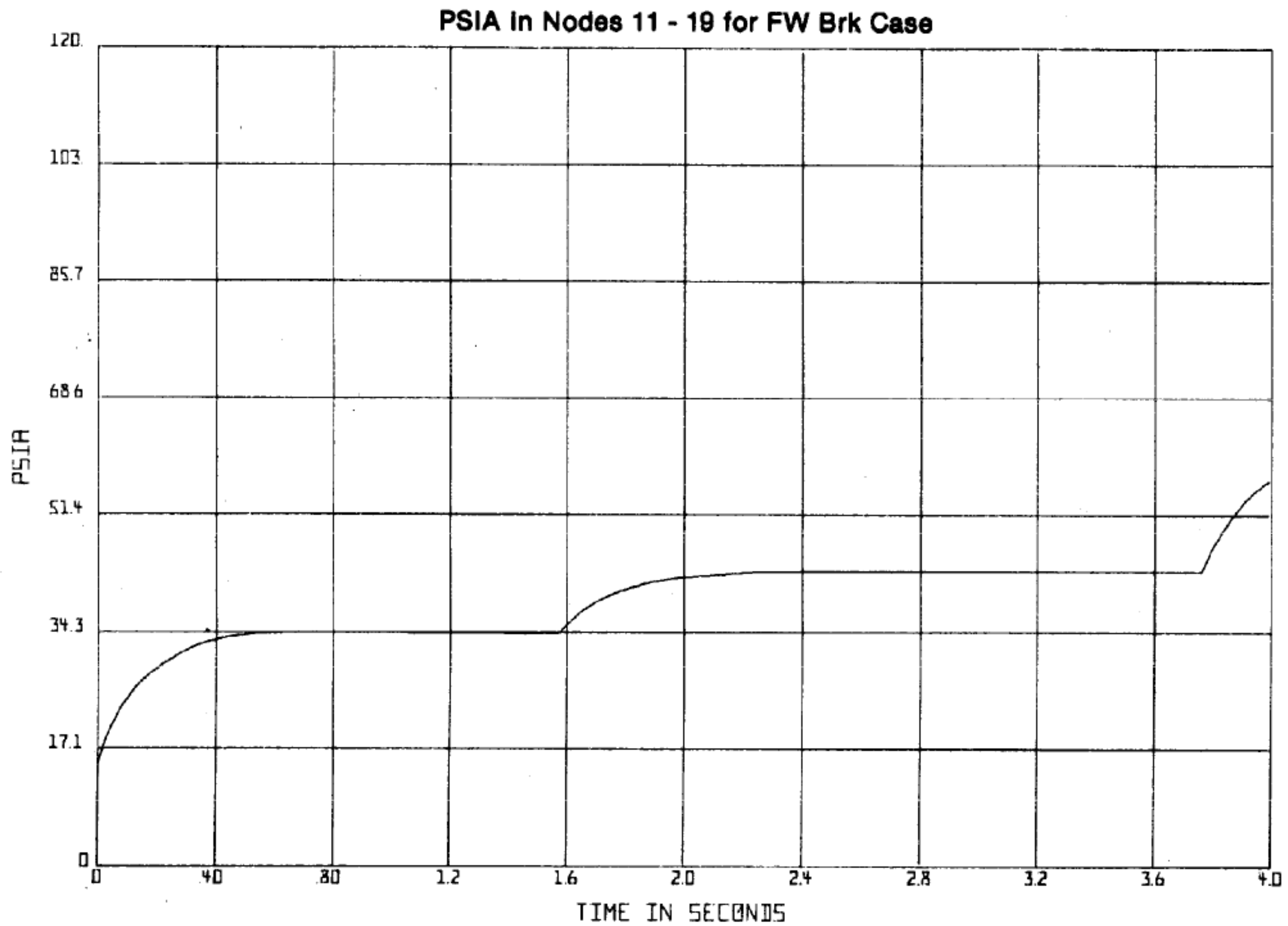
REV 19 7/01

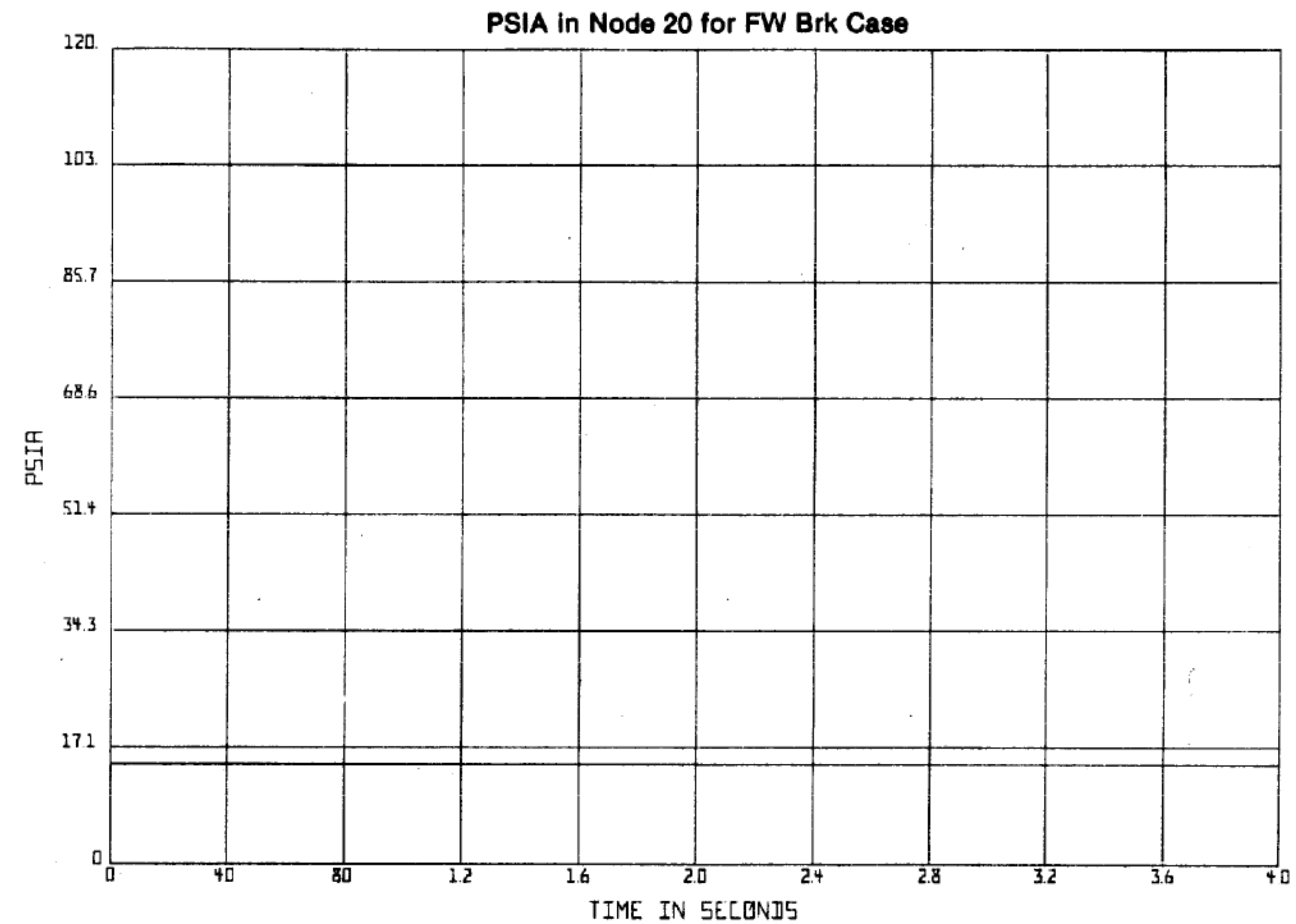
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER BREAK PRESSURE IN NODES 5, 6, 7, 8, 9, AND 10

FIGURE 6A-33 (SHEET 2 OF 3)





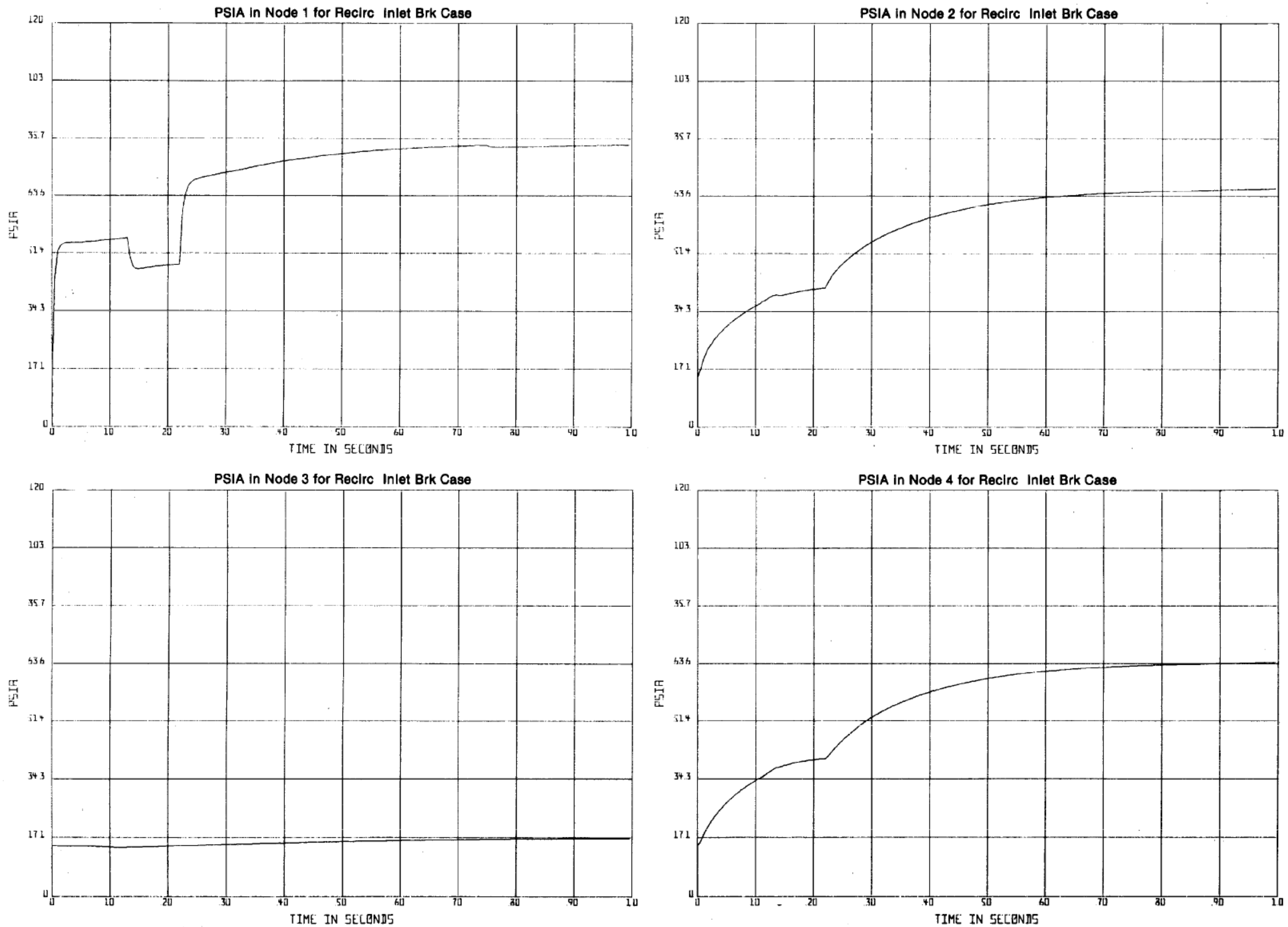
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER BREAK PRESSURE IN NODES 11-20

FIGURE 6A-33 (SHEET 3 OF 3)



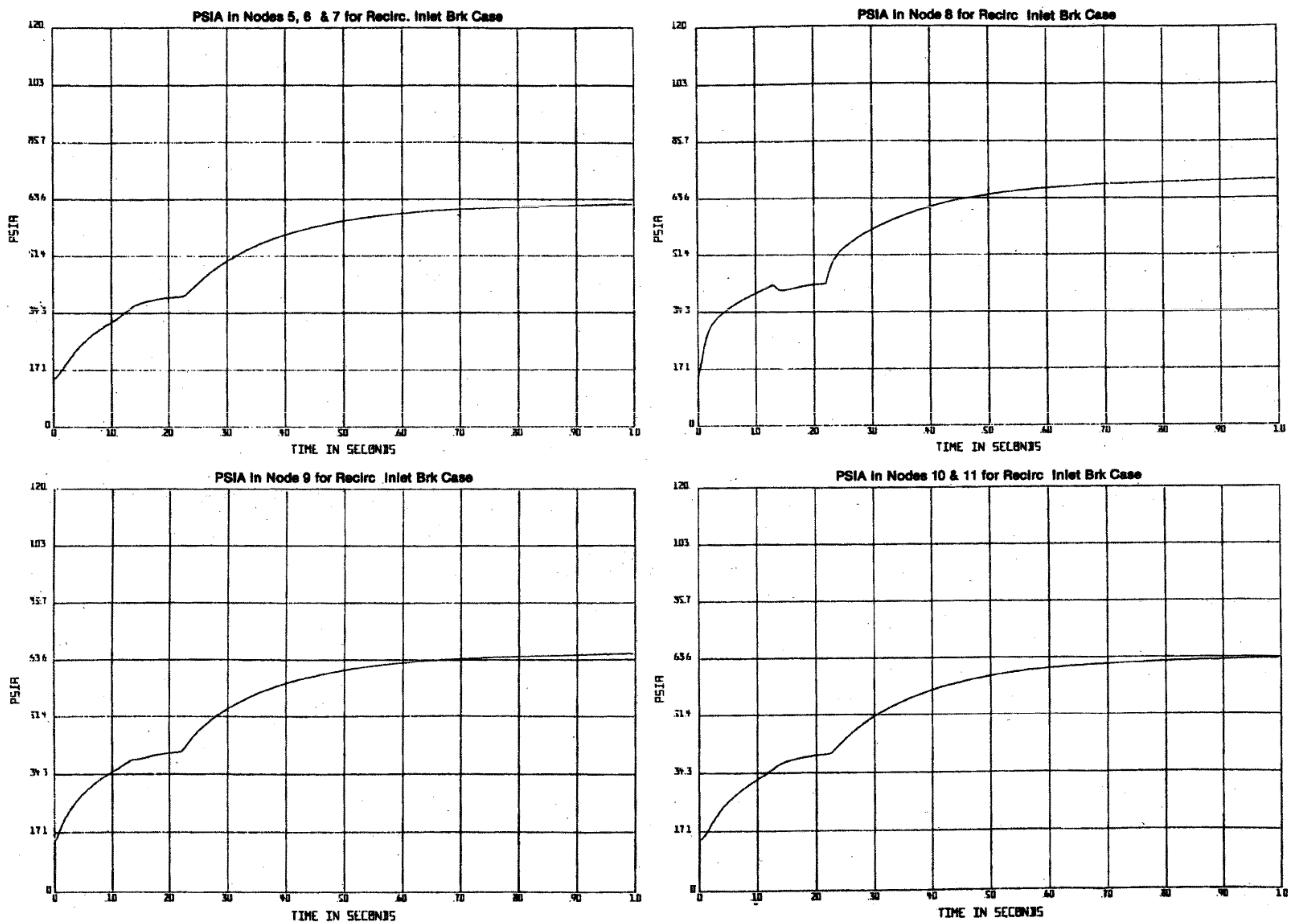
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION INLET BREAK PRESSURE IN NODES 1, 2, 3, AND 4

FIGURE 6A-34 (SHEET 1 OF 3)



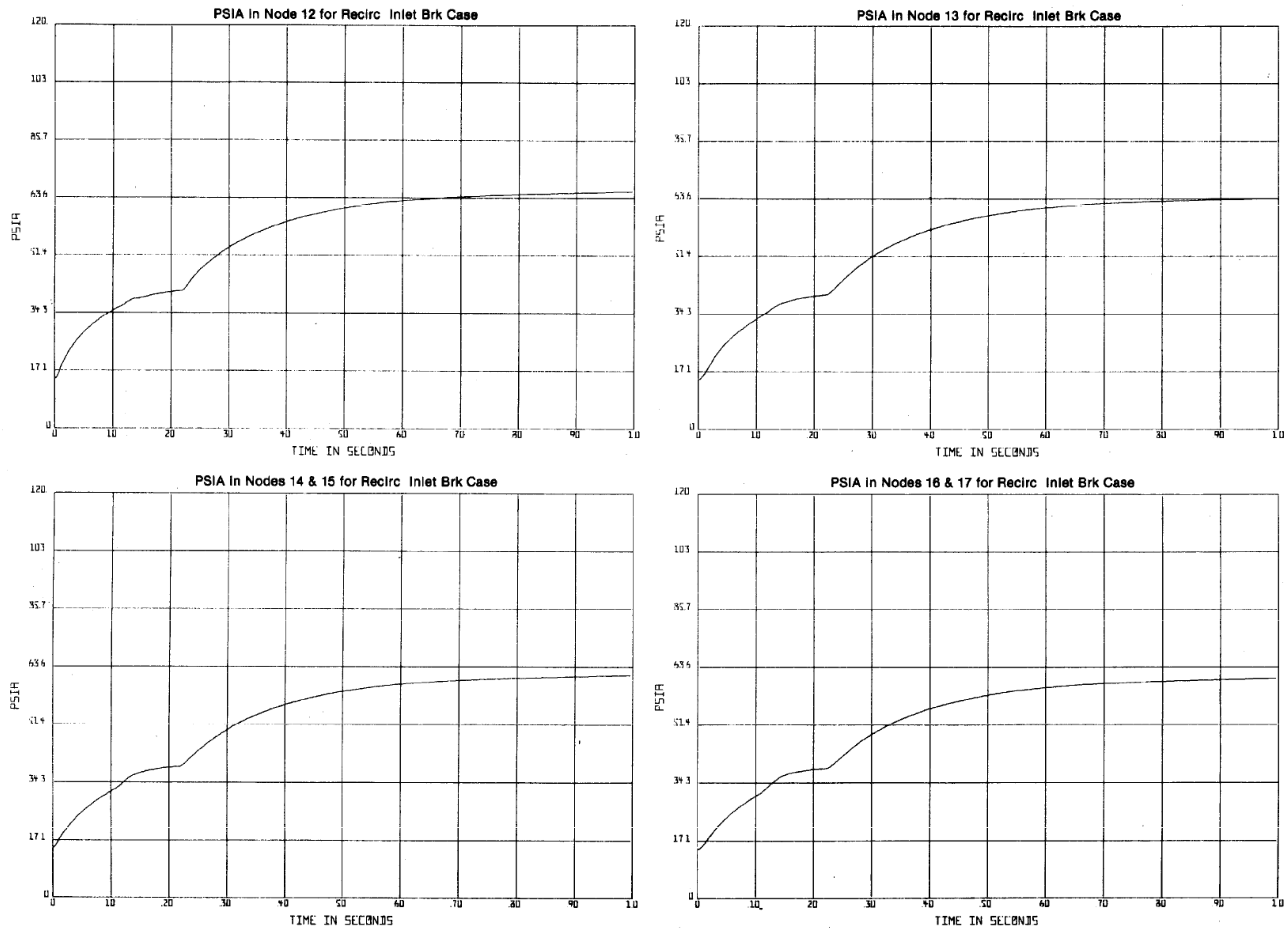
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION INLET BREAK PRESSURE IN NODES 5-7, 8, 9, 10, AND 11

FIGURE 6A-34 (SHEET 2 OF 3)



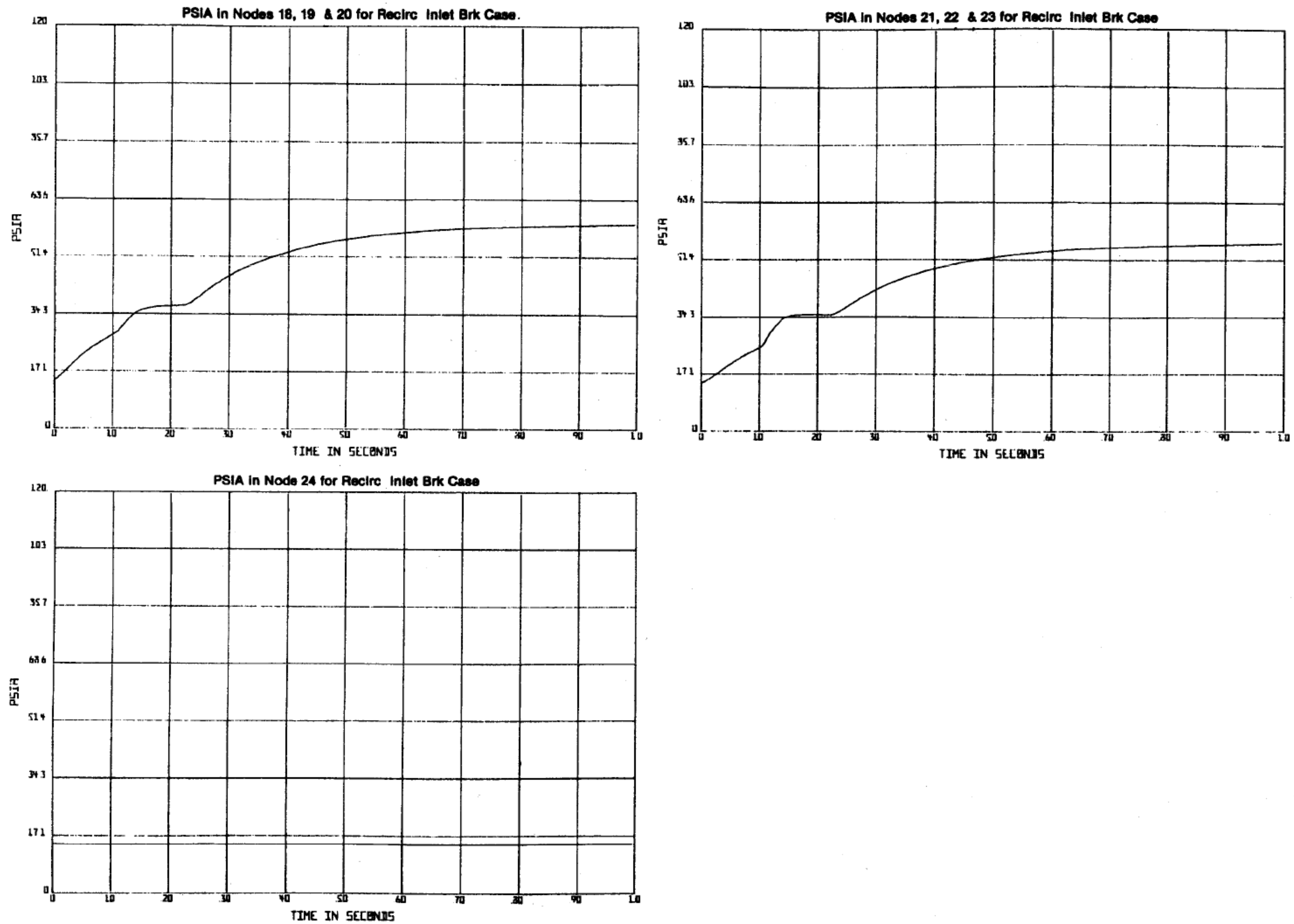
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION INLET BREAK PRESSURE IN NODES 12-15, 16, AND 17

FIGURE 6A-34 (SHEET 3 OF 3)



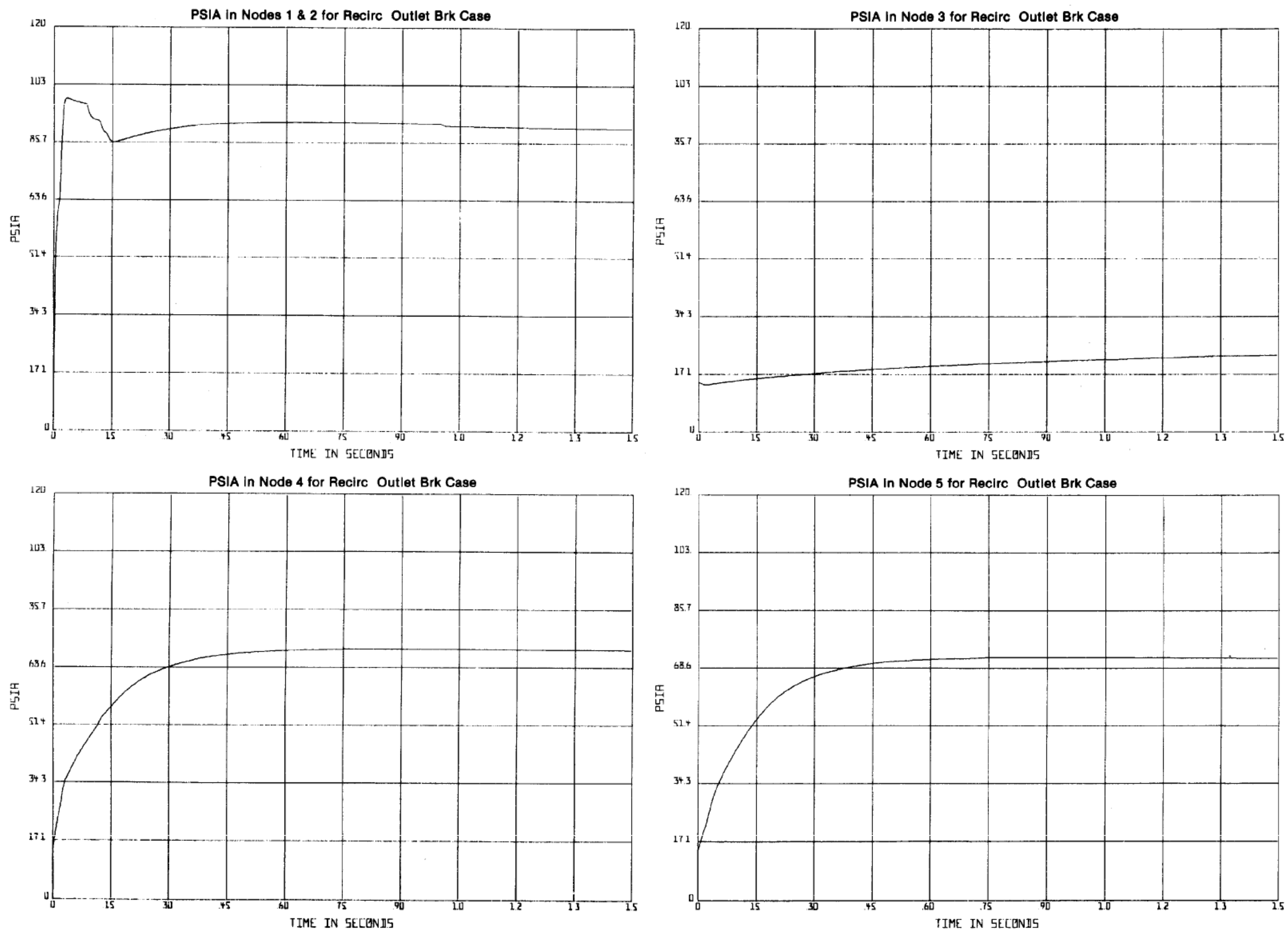
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION INLET BREAK PRESSURE IN NODES 18-24

FIGURE 6A-35



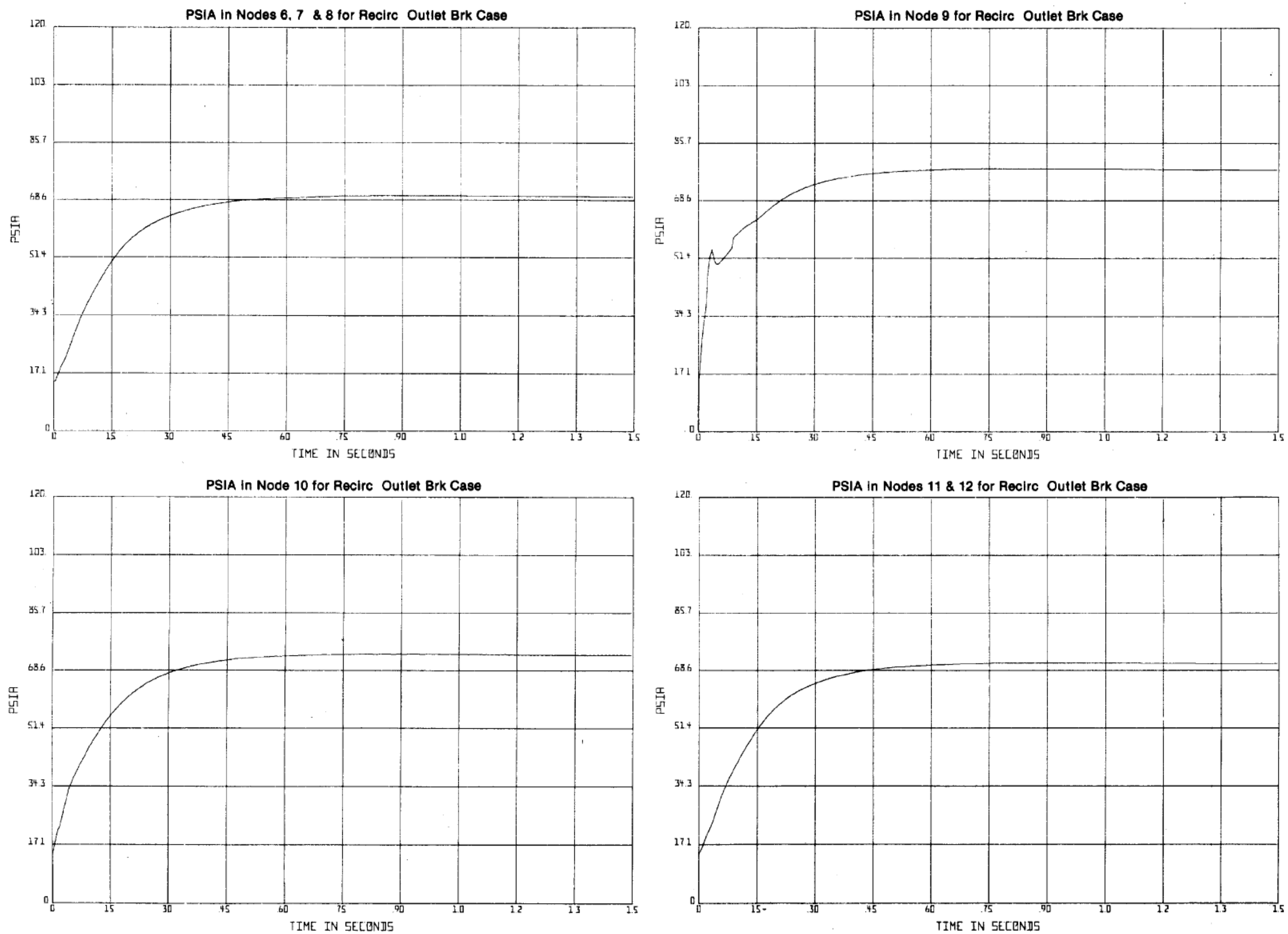
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET BREAK
PRESSURE IN NODES 1-5

FIGURE 6A-36 (SHEET 1 OF 4)



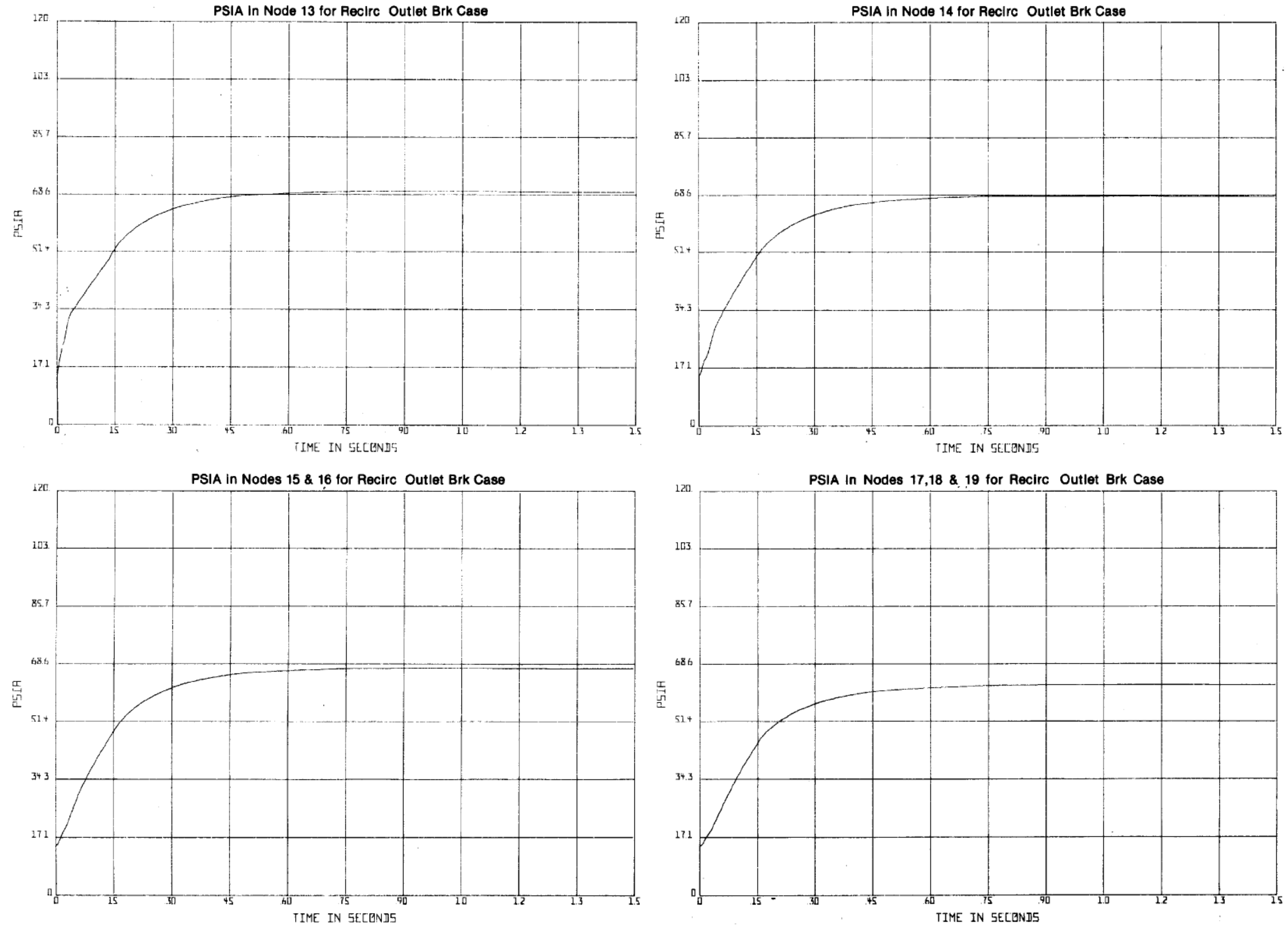
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET BREAK
PRESSURE IN NODES 6-12

FIGURE 6A-36 (SHEET 2 OF 4)



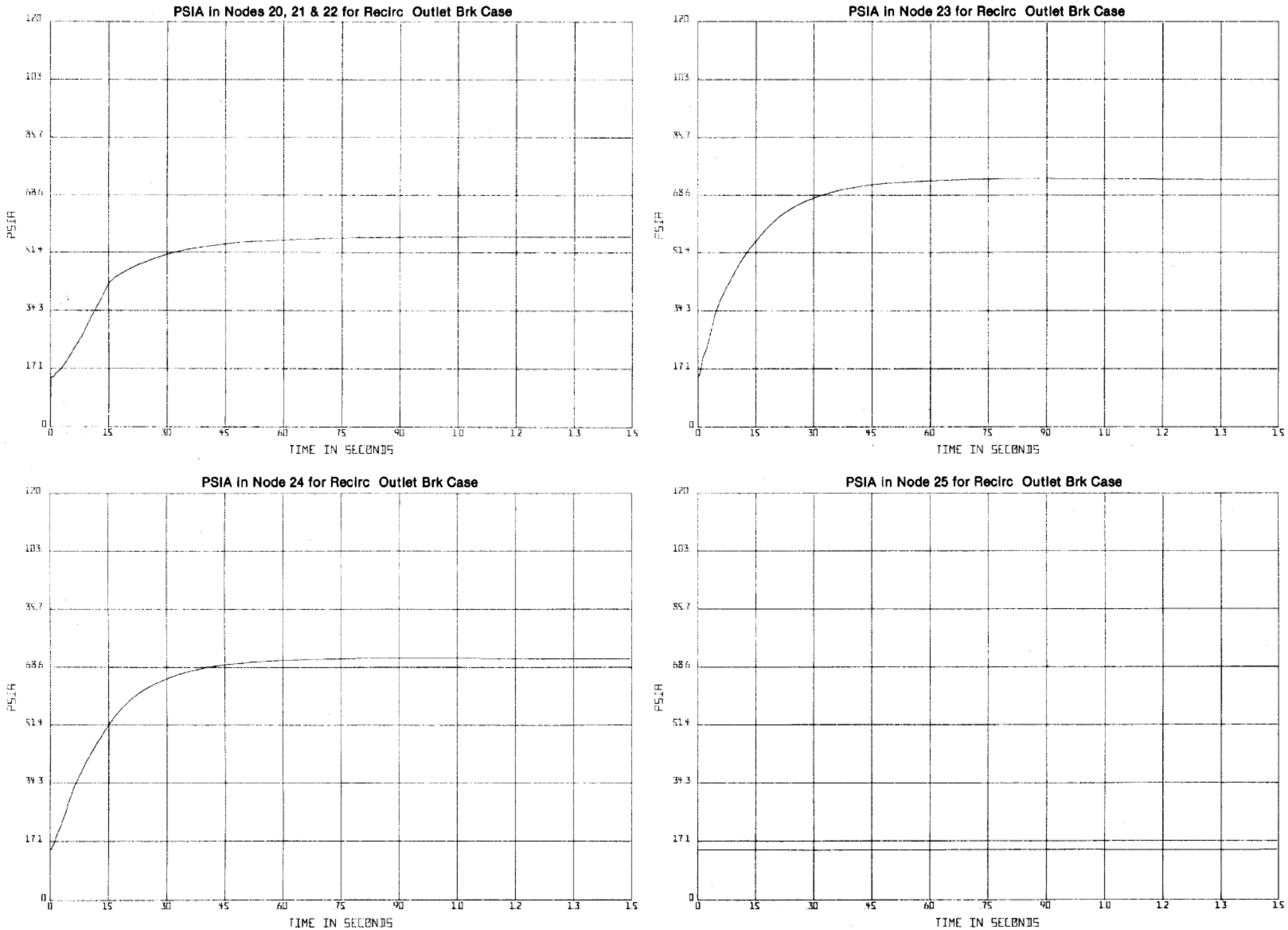
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET BREAK
PRESSURE IN NODES 13-19

FIGURE 6A-36 (SHEET 3 OF 4)



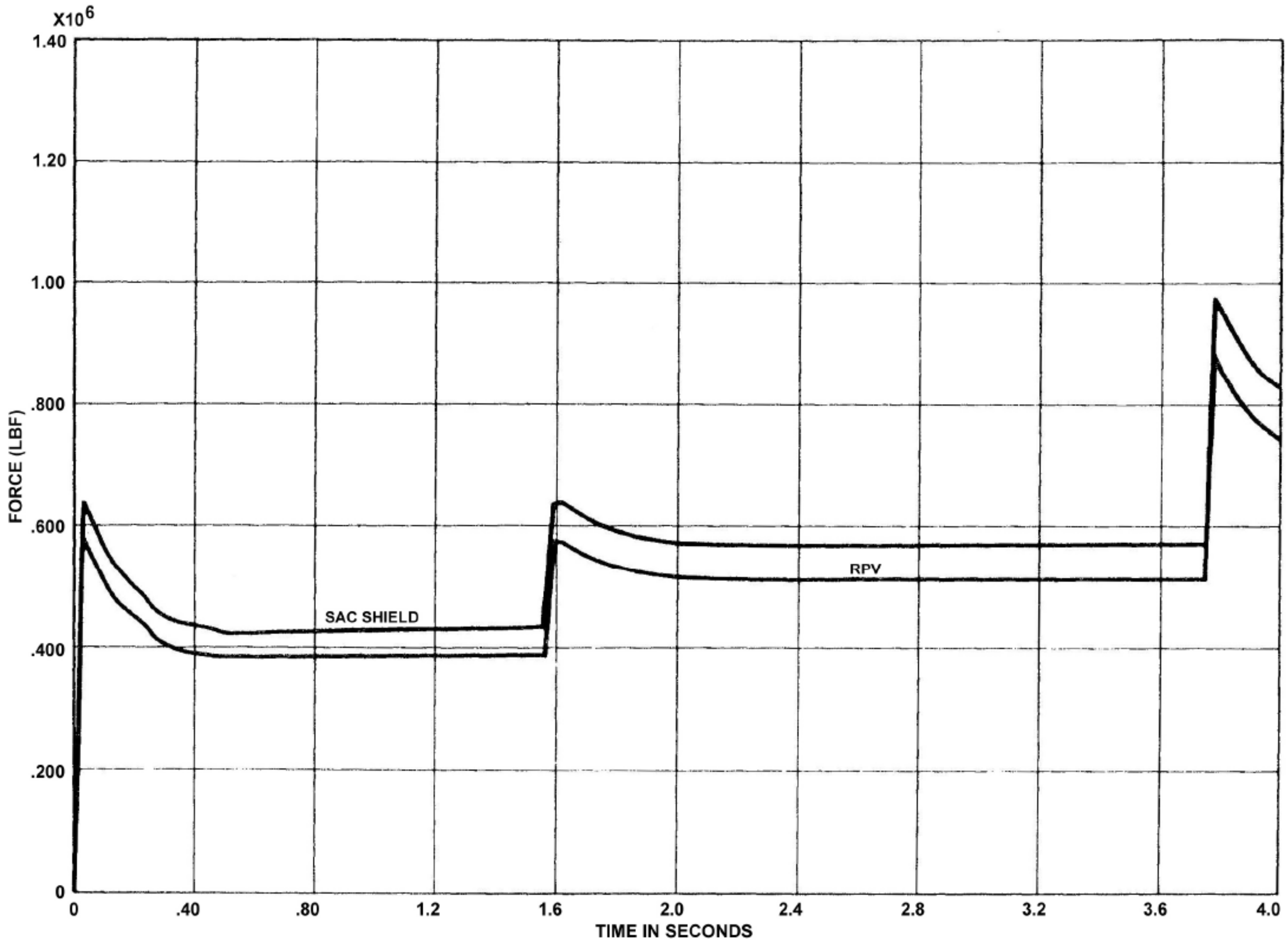
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET BREAK
PRESSURE IN NODES 20-25

FIGURE 6A-36 (SHEET 4 OF 4)



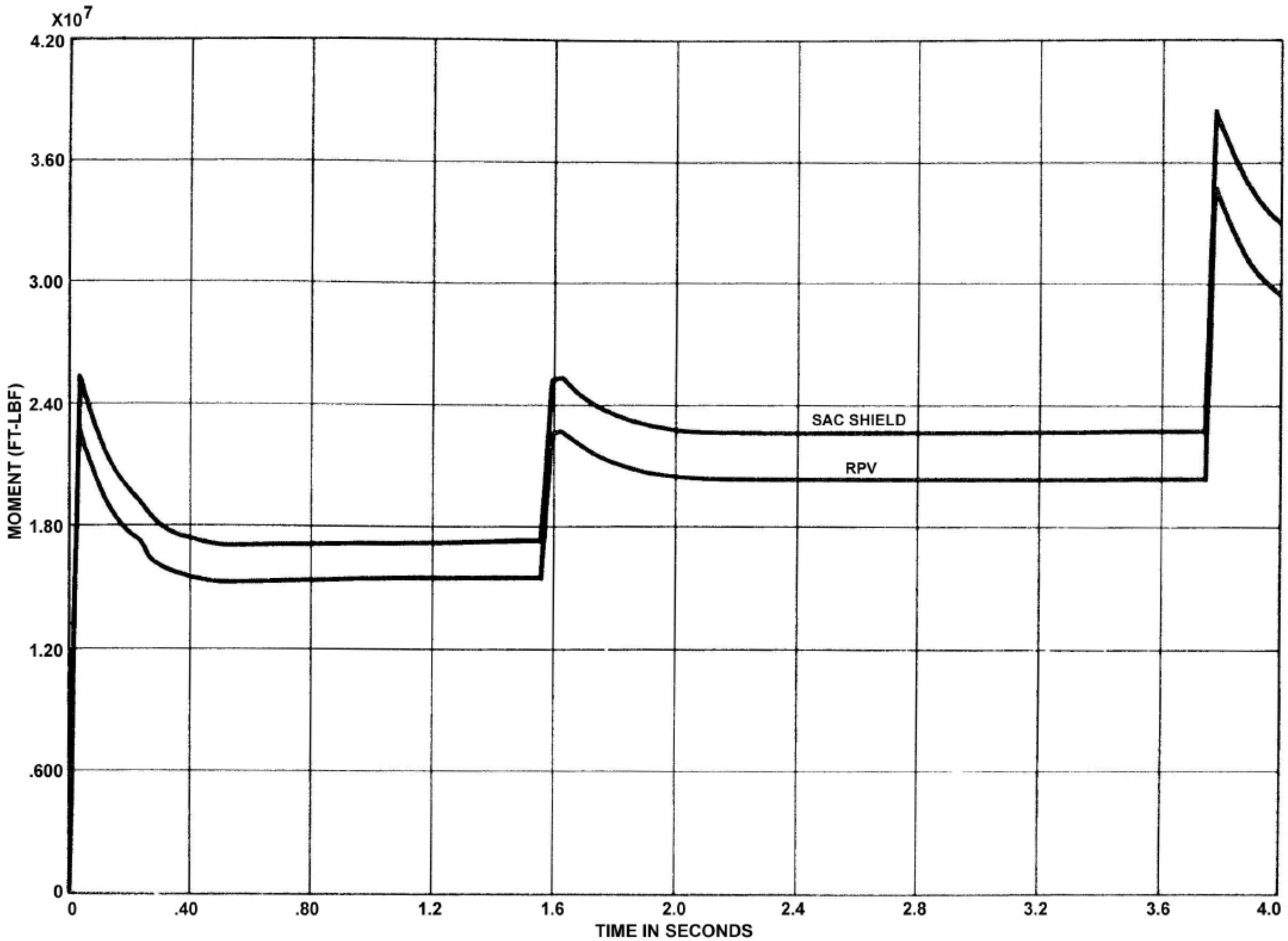
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FORCES ON RPV, SACRIFICIAL SHIELD FOR FEEDWATER BREAK ΣF_X

FIGURE 6A-37



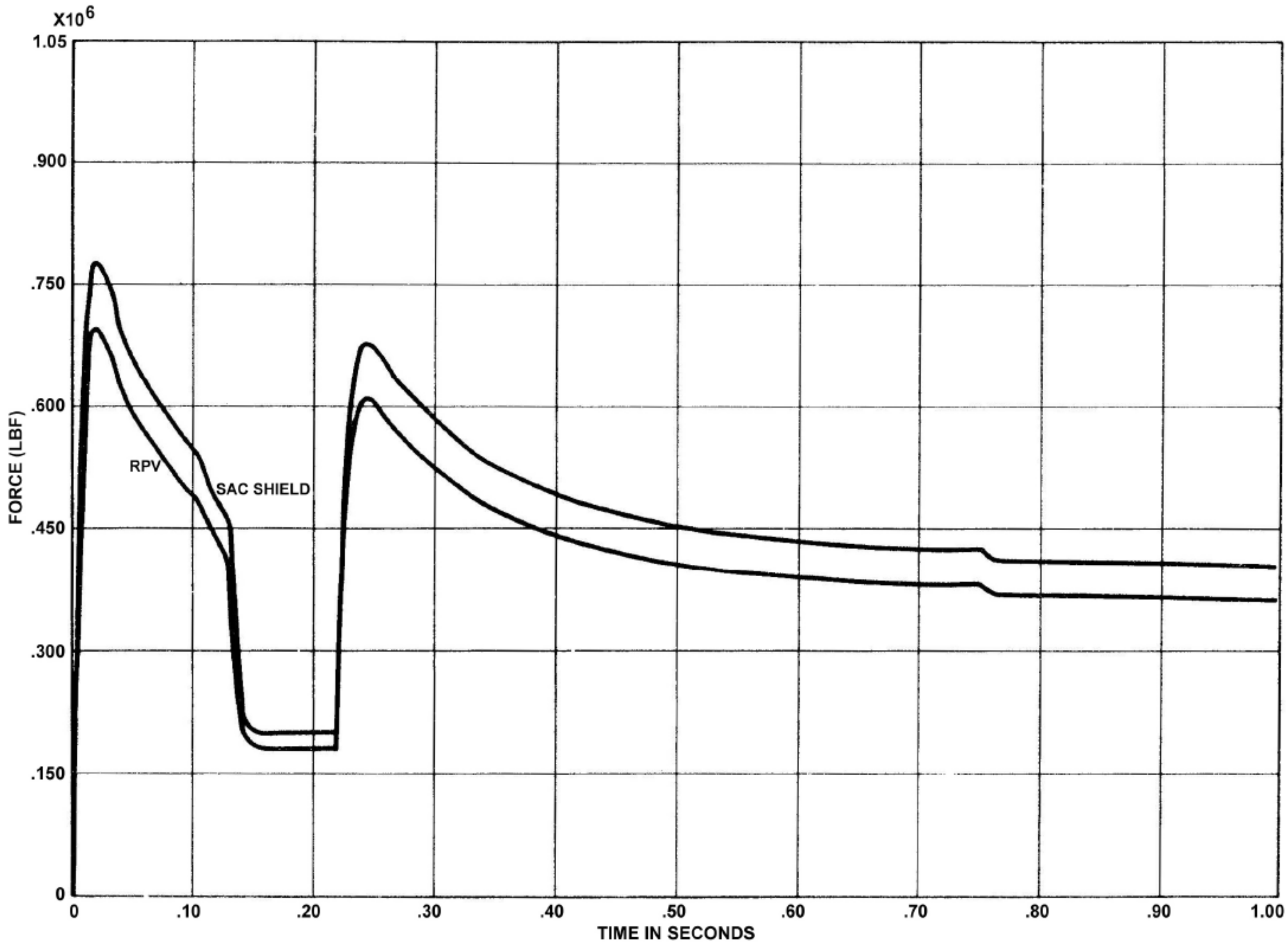
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MOMENTS ON RPV, SACRIFICIAL SHIELD FOR FEEDWATER BREAK ΣM_Y

FIGURE 6A-38

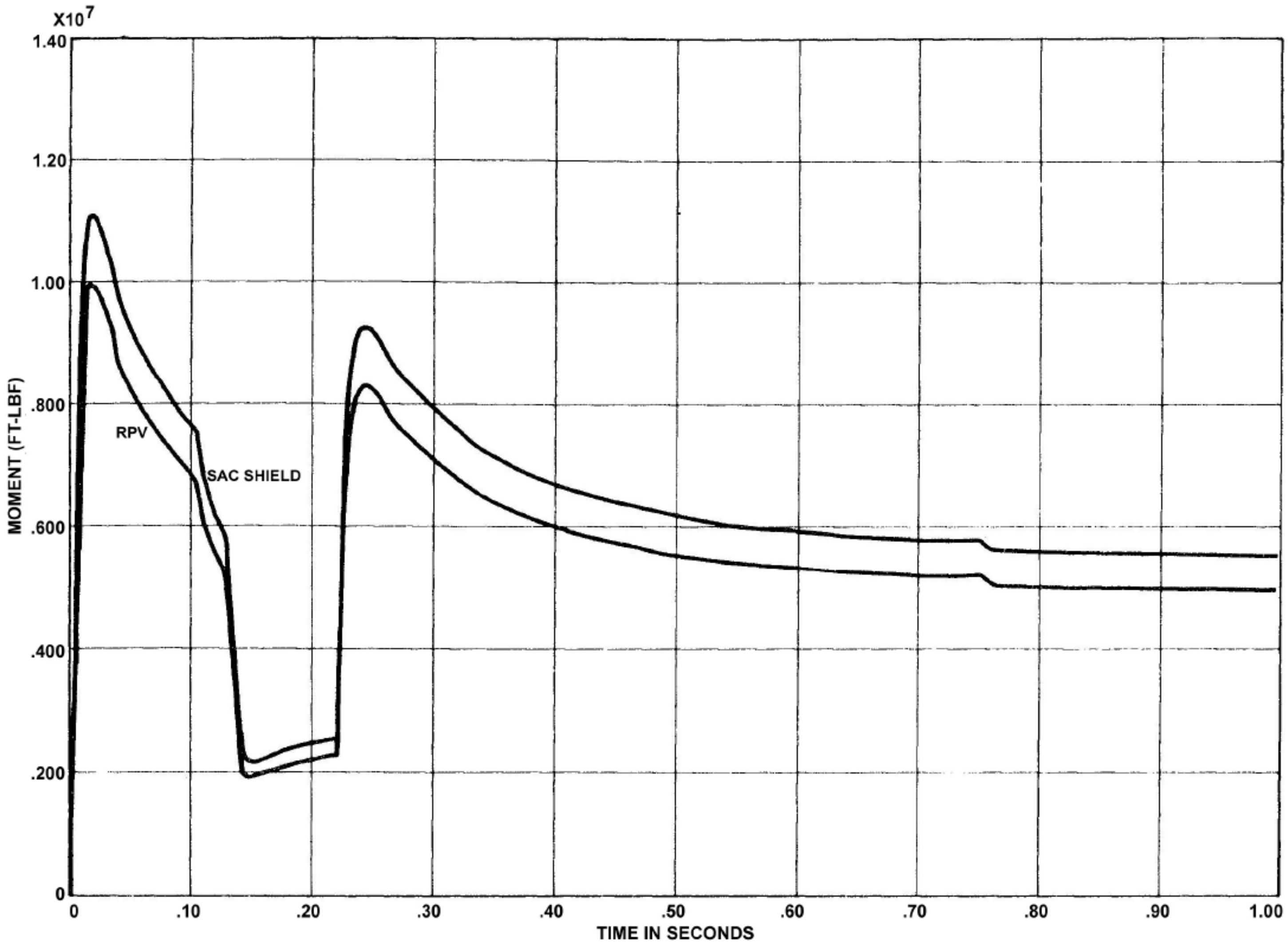


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FORCES ON RPV, SACRIFICIAL SHIELD FOR RECIRCULATION INLET BREAK ΣF_X

FIGURE 6A-39



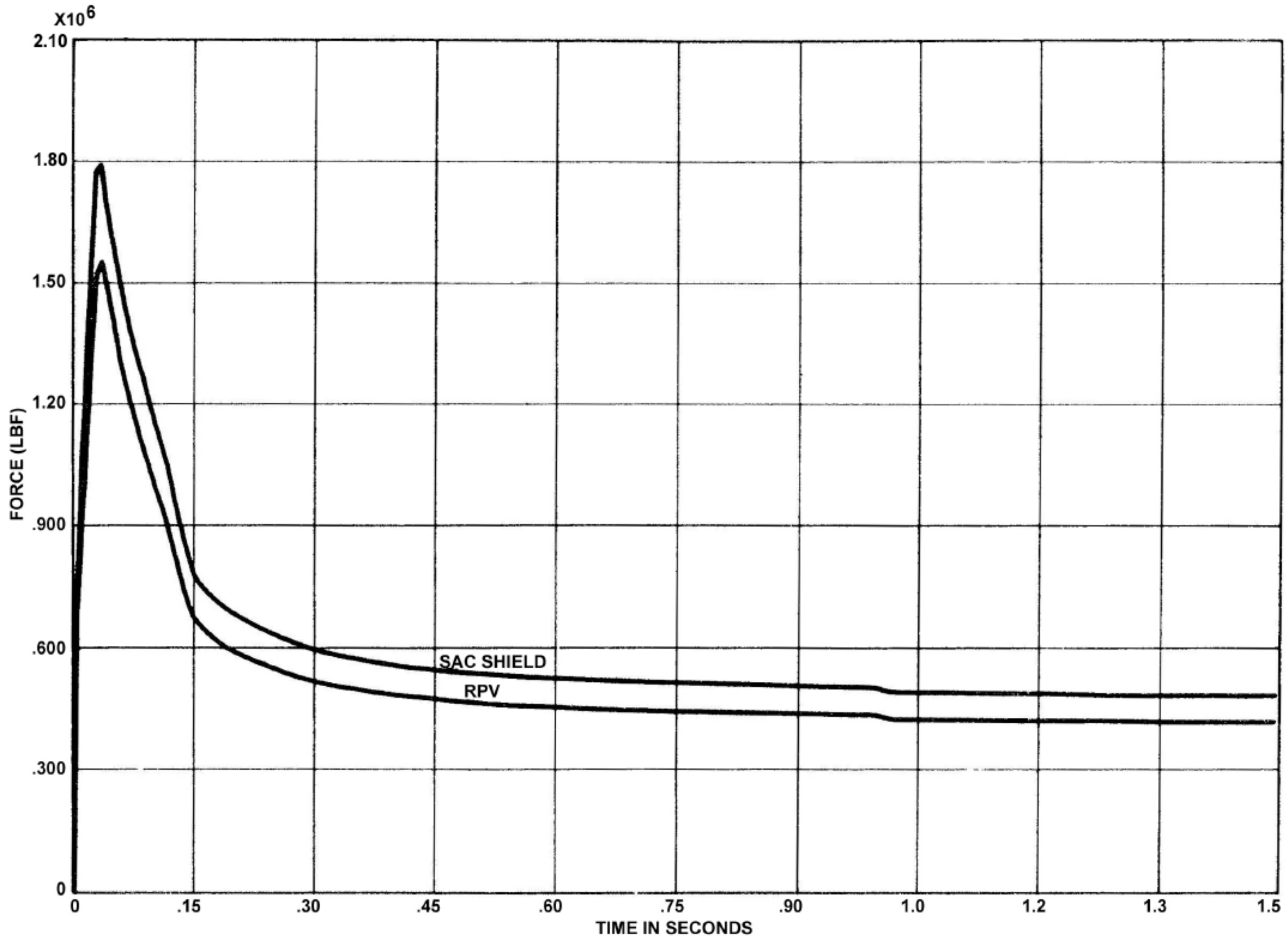
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MOMENTS ON RPV, SACRIFICIAL SHIELD FOR RECIRCULATION INLET BREAK ΣM_Y

FIGURE 6A-40



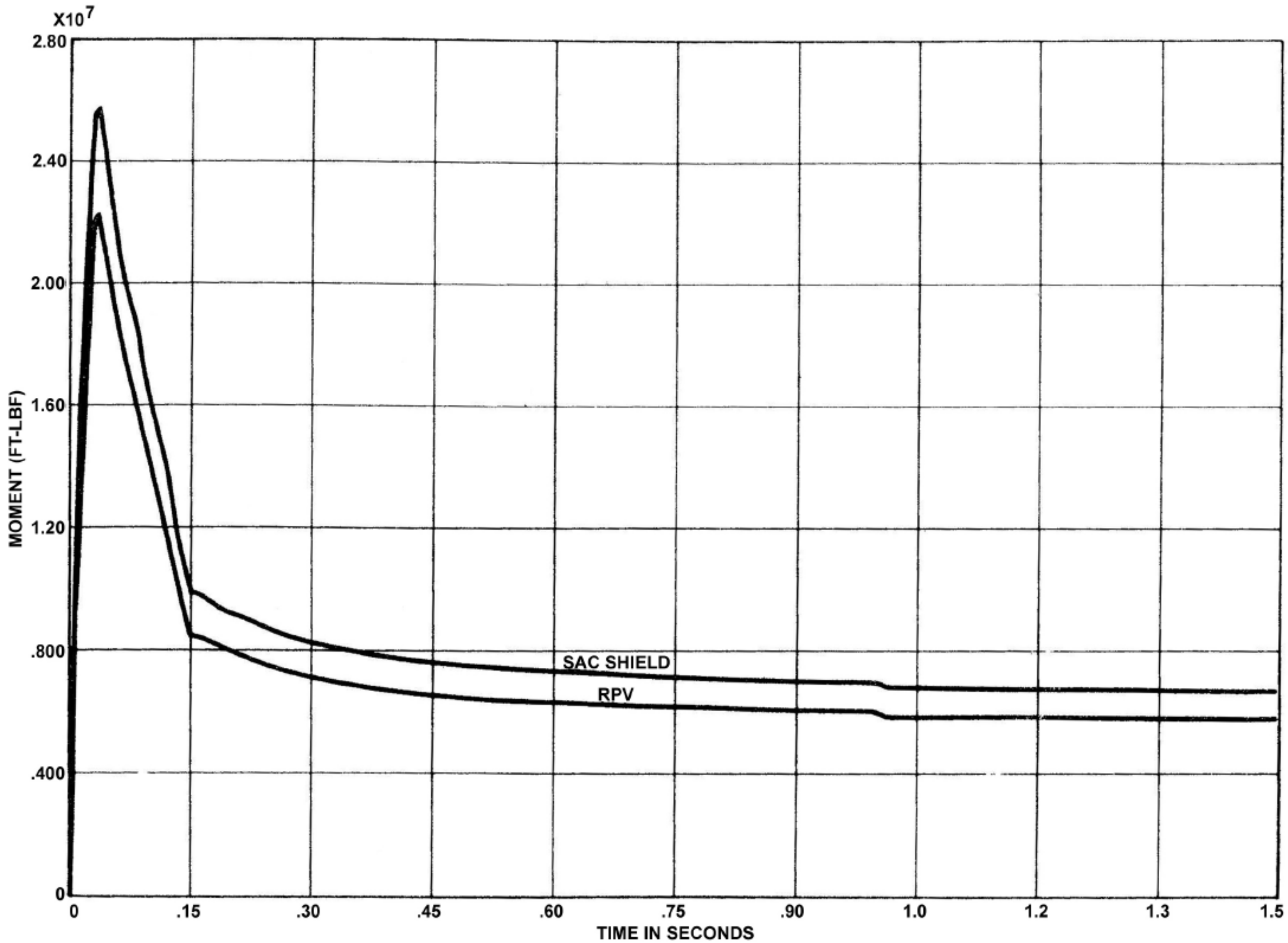
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FORCES ON RPV, SACRIFICIAL SHIELD FOR RECIRCULATION OUTLET BREAK ΣF_X

FIGURE 6A-41

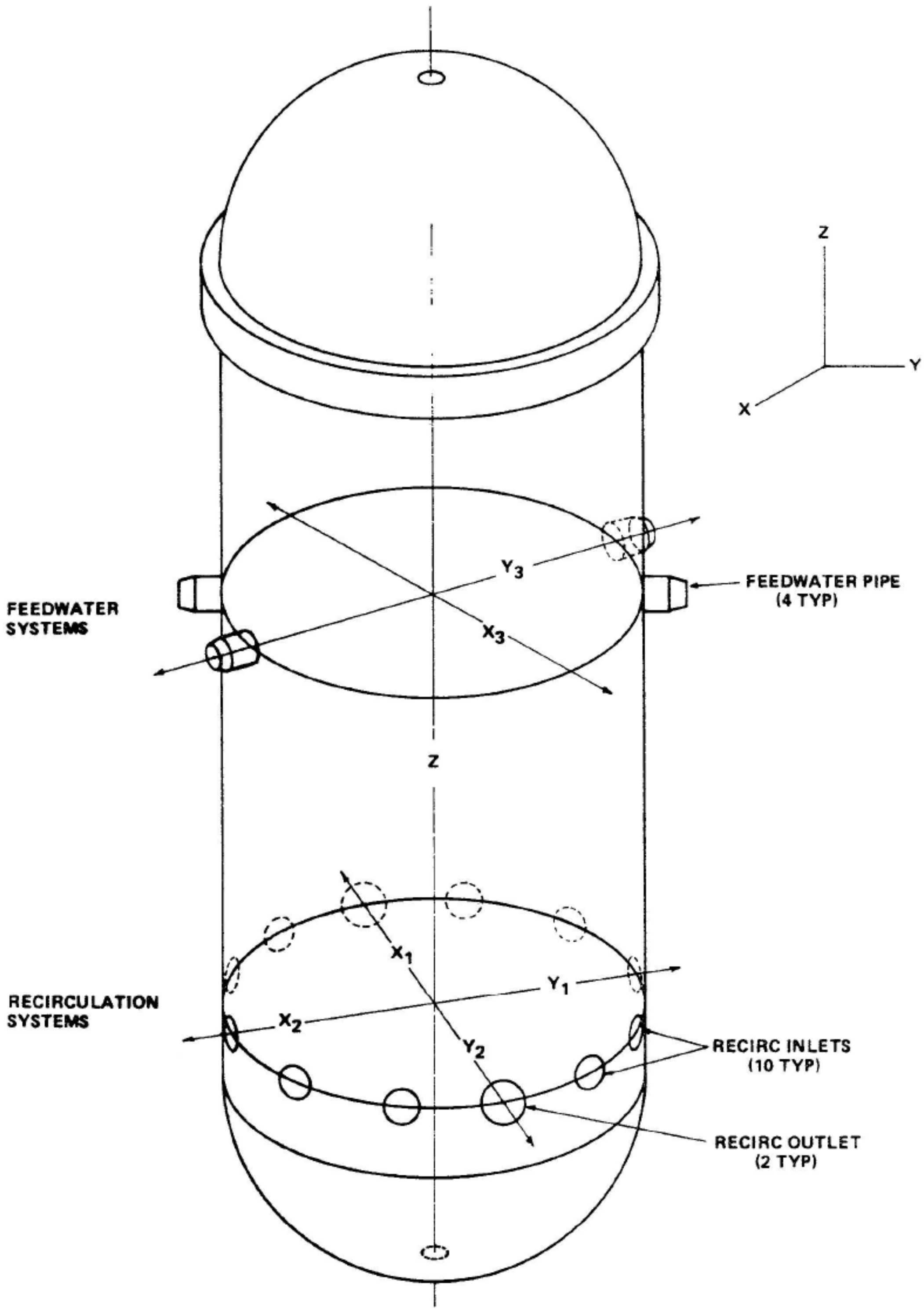


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

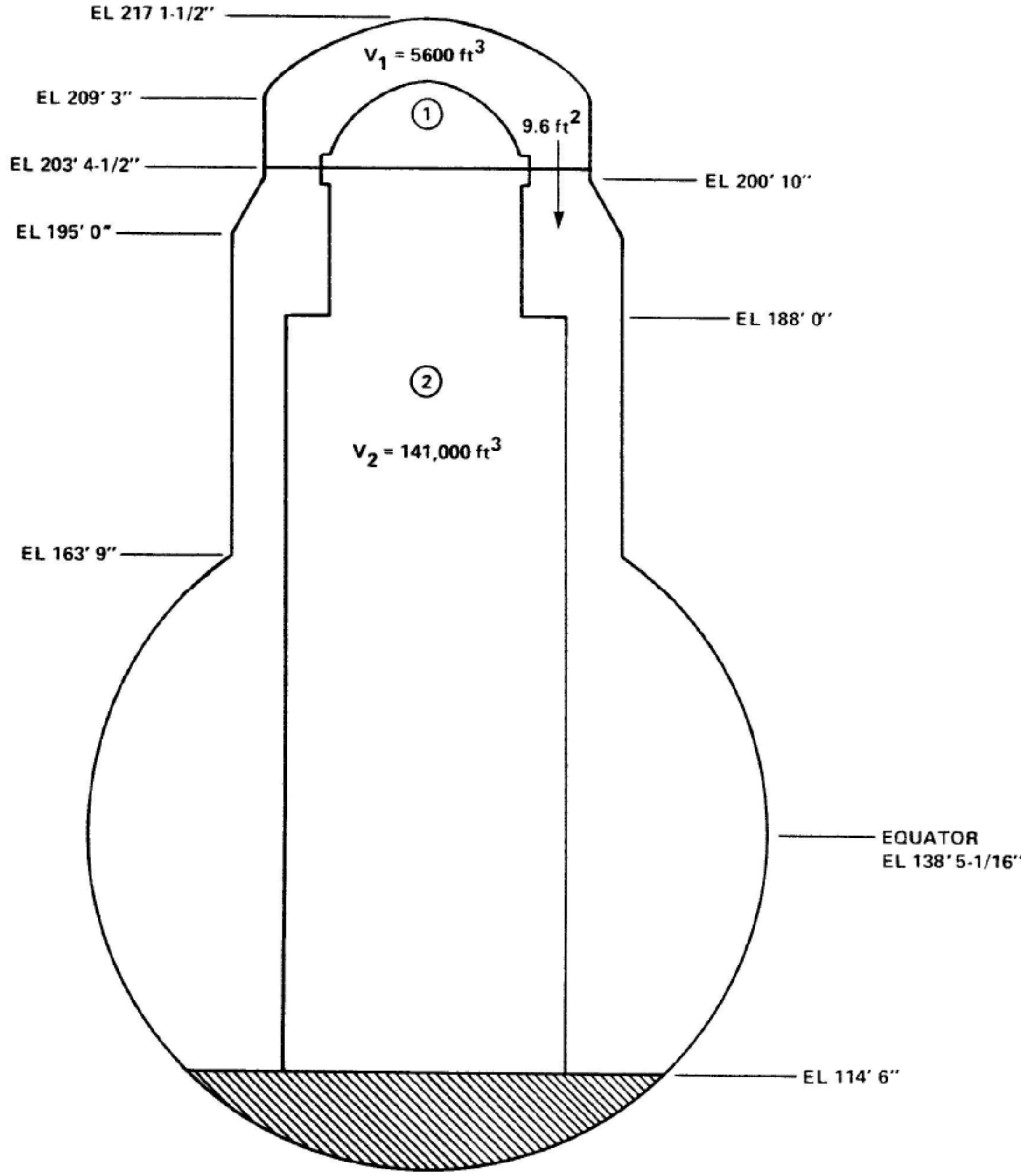
MOMENTS ON RPV, SACRIFICIAL SHIELD
RECIRCULATION OUTLET BREAK

FIGURE 6A-42



REV 19 7/01

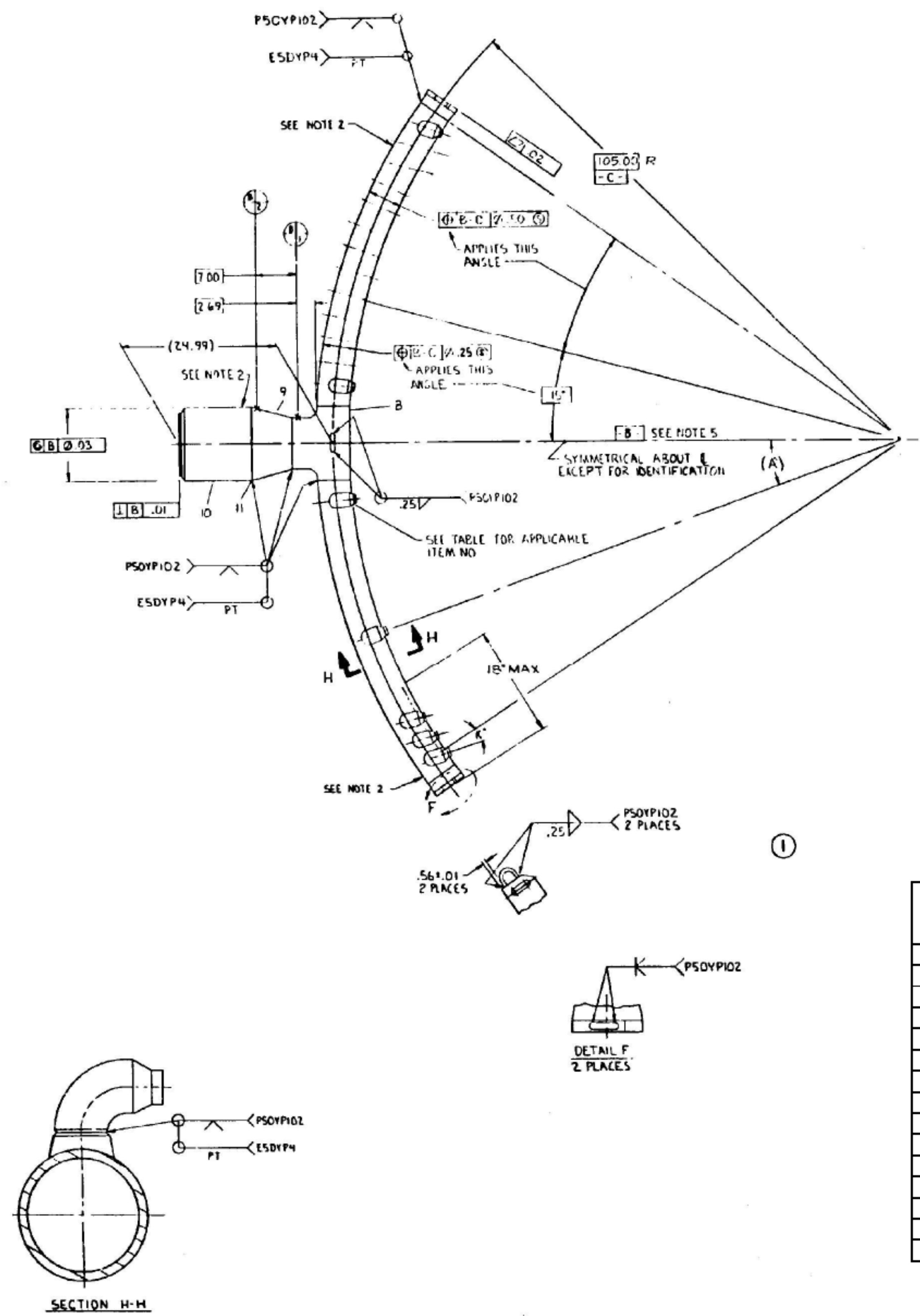
SOUTHERN COMPANY Energy to Serve Your World® SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	AXIS ORIENTATION
	FIGURE 6A-43

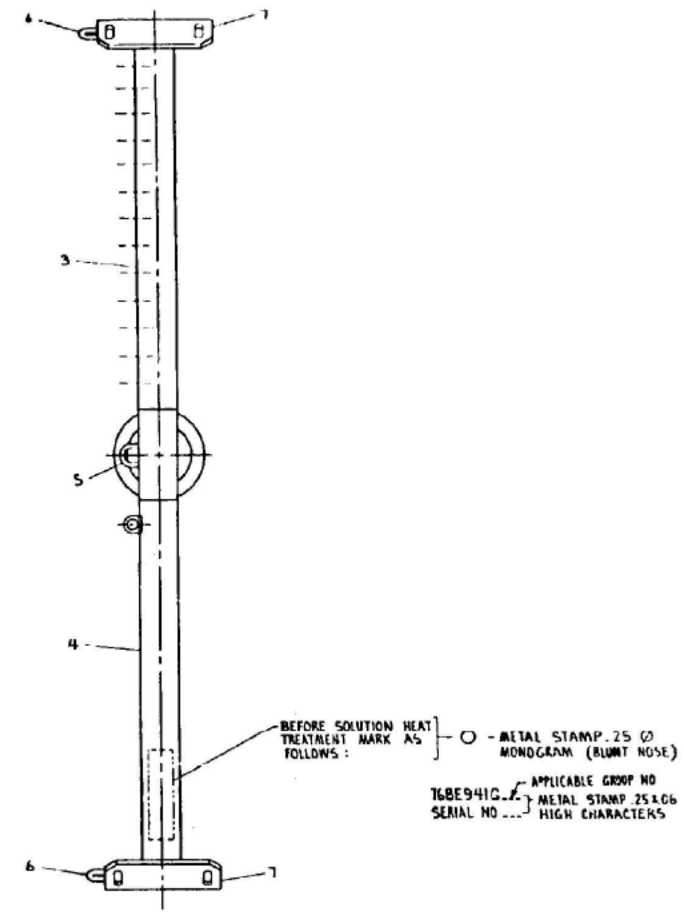


NOTE: RPV HEAD SPRAY IS DEACTIVATED; HEAD SPRAY INFORMATION IS MAINTAINED FOR HISTORICAL PURPOSES.

REV 19 7/01

SOUTHERN COMPANY Energy to Serve Your World® SOUTHERN NUCLEAR OPERATING COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2	SCHEMATIC FLOW DIAGRAM FOR HEAD SPRAY LINE BREAK
	FIGURE 6A-44





NOTES:

1. WELDING REQUIREMENTS PER 209A4290.
2. ORIENT ITEM 3, 4 & 10 SO THAT END MARKED WITH "X" IS AT THIS END.
3. PACKAGE & STORAGE PER ITEM 12.
4. SOLUTION HEAT TREAT PER P10HYP28 AFTER WELDING. COLD STRAIGHTENING AFTER SOLUTION HEAT TREATMENT IS PERMITTED IF REQUIRED TO MEET CRAWLING TOLERANCES PROVIDED STRAIN DOES NOT EXCEED 2.5% AND HARDNESS DOES NOT EXCEED R_B90.

   STRAIGHTENING BY WELD DRAW BEADING OR HEATING IS NOT PERMITTED AFTER SOLUTION HEAT TREATMENT.
5. CATUM AXIS [–B–] IS ESTABLISHED BY AVERAGE OUTSIDE DIAMETERS AT TARGET LOCATIONS.

A°	APPLICABLE ITEM NO. PER HOLE LOCATION ITEM NO.	K° ± 4°		QTY/ SPARGER	AREA (IN^2) SPARGER	TOTAL AREA
6°	14	0°	1.25 DIA	2	2.44	9.76
8°	15	0°	1.38 DIA	8	10.5	42.00
10°	15	0°				
12°	15	0°				
14°	15	0°				
16°	13	0°	1.0 DIA	10	7.81	31.24
18°	13	0°				
20°	13	0°				
22°	13	0°				
24°	13	0°				
26°	14	0°	1.25 DIA	4	4.89	19.56
28°	14	0°				
30°	16	30°	1.75 DIA	6	14.39	57.56
32°	16	30°				
34°	16	30°				
					40.03	160.12 in^2

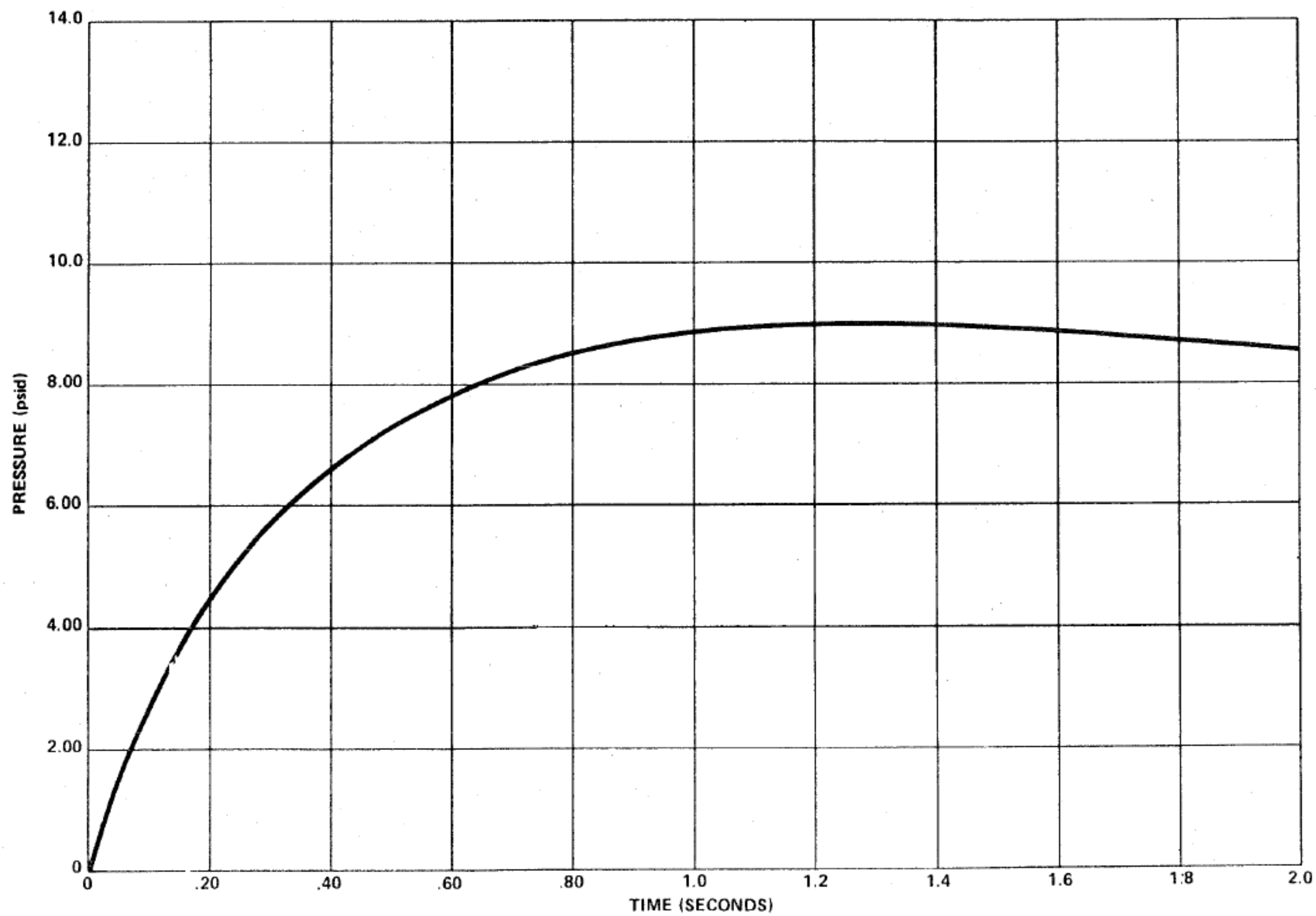
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FEEDWATER SPARGER

FIGURE 6A-45



NOTE: RPV HEAD SPRAY IS DEACTIVATED;
HEAD SPRAY INFORMATION IS MAINTAINED FOR HISTORICAL PURPOSES.

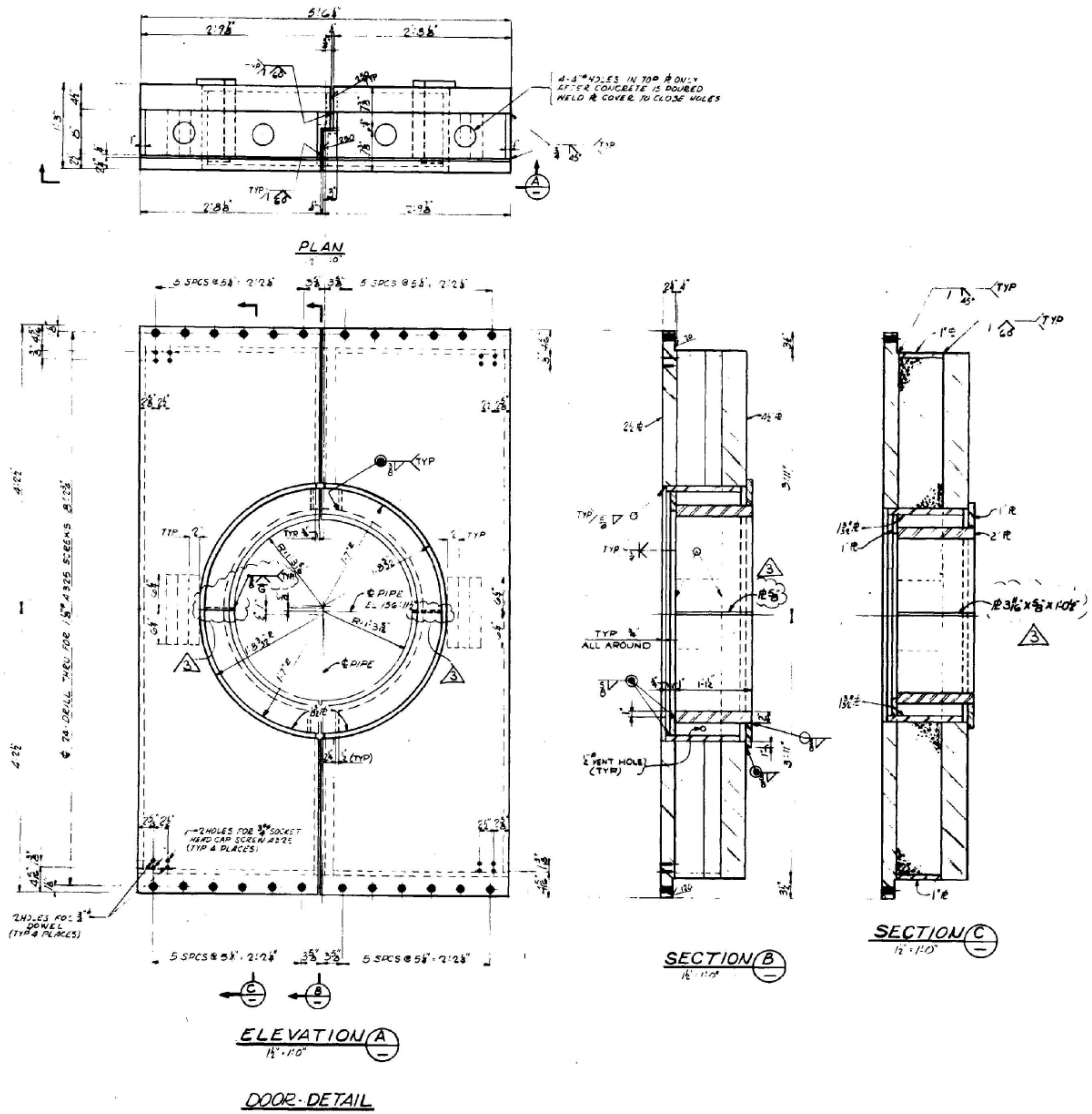
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HEAD SPRAY LINE BREAK
ΔP BETWEEN COMPARTMENTS 1 AND 2

FIGURE 6A-46



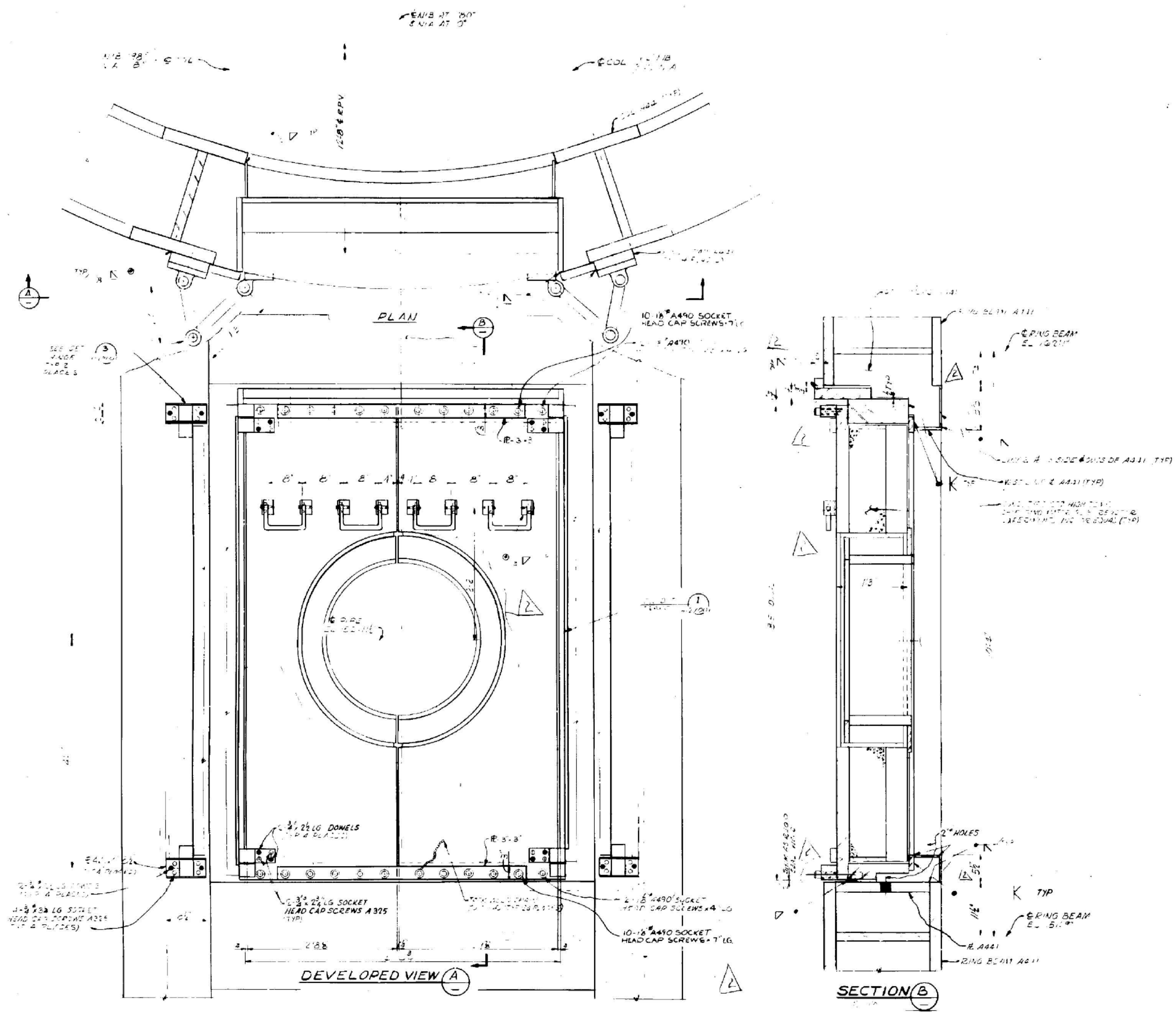
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

INSERVICE INSPECTION DOORS

FIGURE 6A-47 (SHEET 1 OF 2)



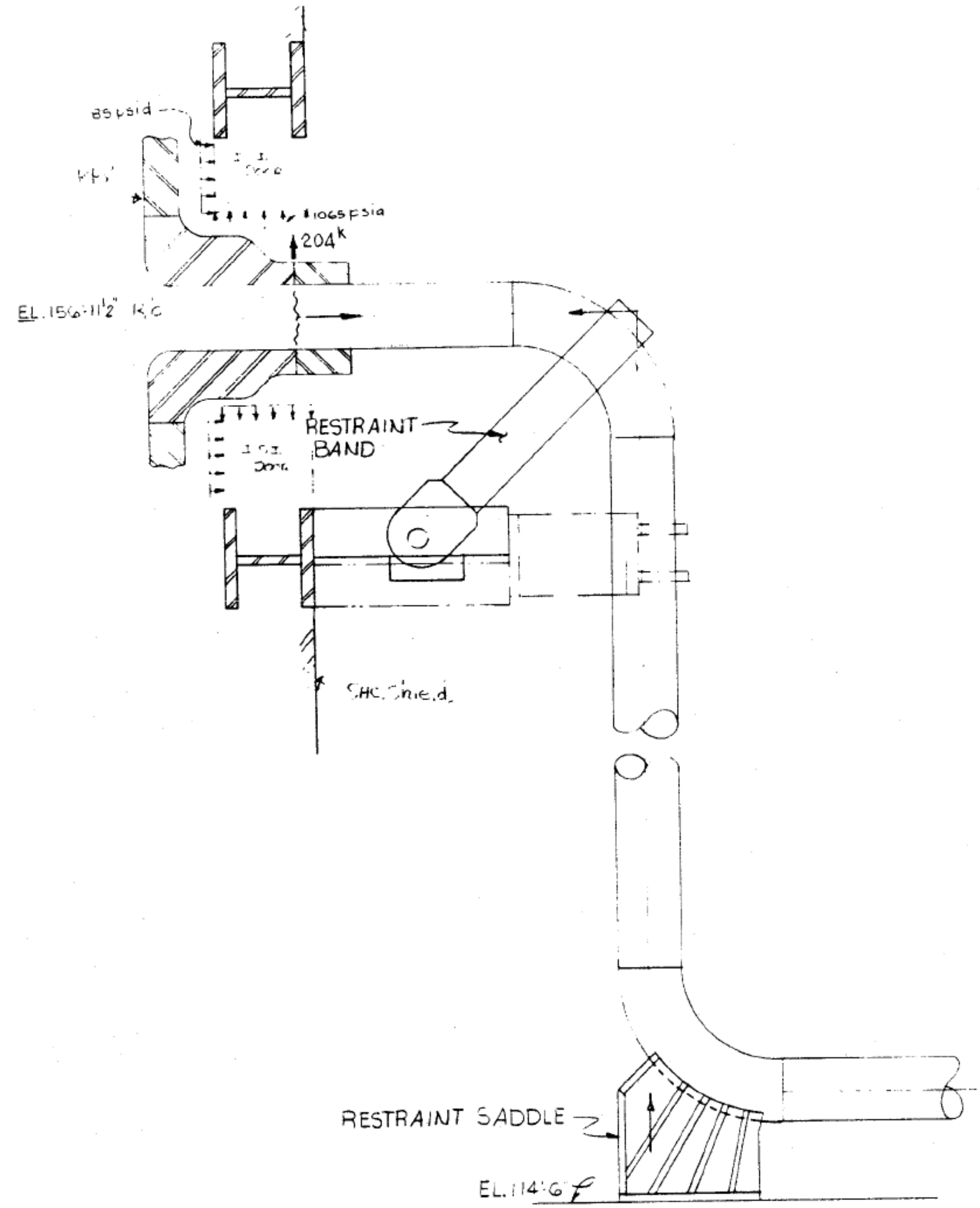
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

INSERVICE INSPECTION DOORS

FIGURE 6A-47 (SHEET 2 OF 2)



REV 19 7/01

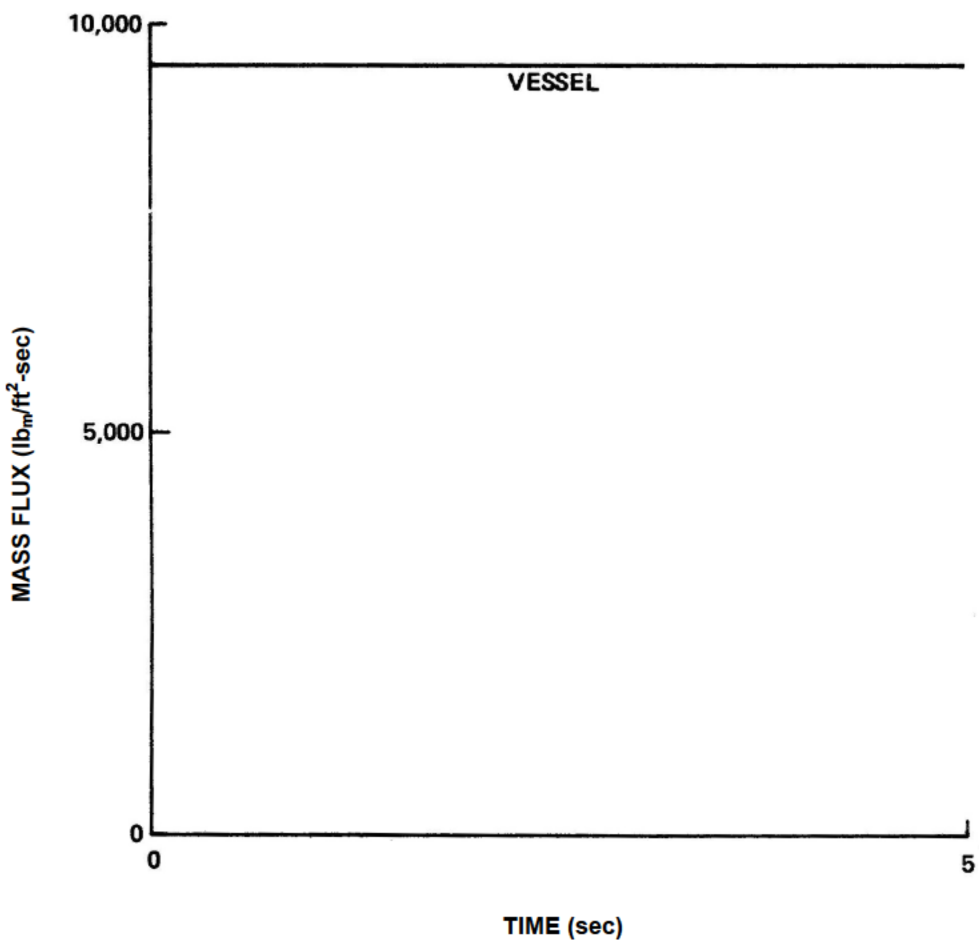
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RECIRCULATION OUTLET RESTRAINT
BAND AND SADDLE ARRANGEMENT

FIGURE 6A-48

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)	0	9500

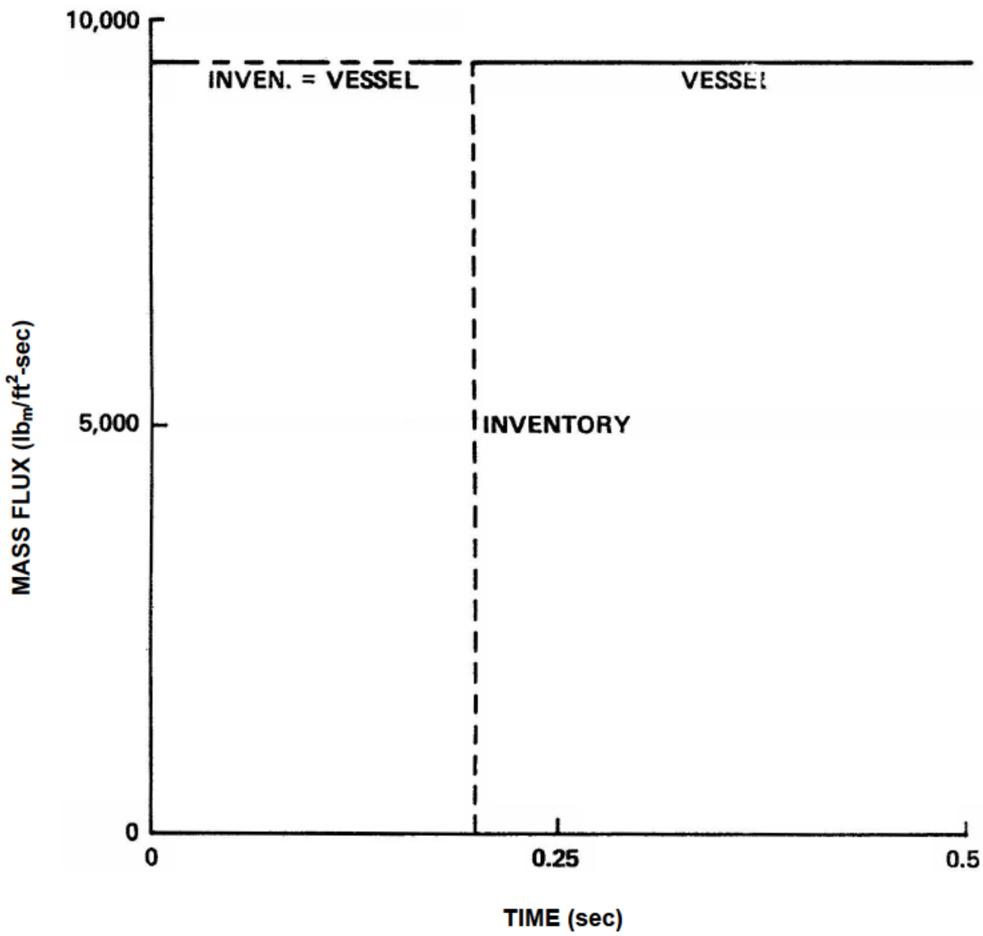


REV 19 7/01

MASS FLUX VS TIME
10-in. CORE SPRAY LINE

FIGURE 6A-49

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)		
$0 \le t \le 0.2$ sec.	9500	9500
$0.2 < t \le 0.5$ sec.	0	9500



The results of the analysis for the RHR suction line break are bounded by the recirculation line break and were not reevaluated for extended power uprate, thermal power optimization, and reactor operating pressure increase.

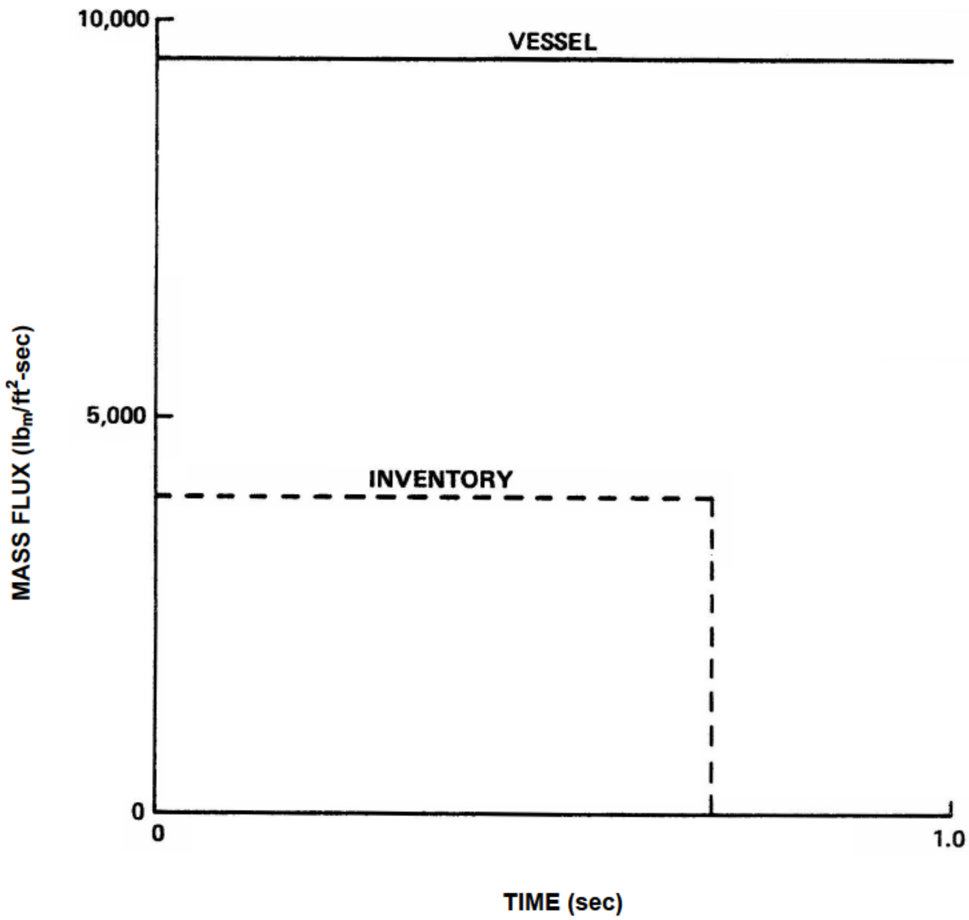
REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
RHR SUCTION

FIGURE 6A-50

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)		
$0 \le t \le 0.7$ sec.	4000	9500
$0.7 < t \le 1.0$ sec.	0	9500



The results of the analysis for the RHR discharge line break are bounded by the recirculation line break and were not reevaluated for extended power uprate, thermal power optimization, and reactor operating pressure increase.

REV 22 9/04

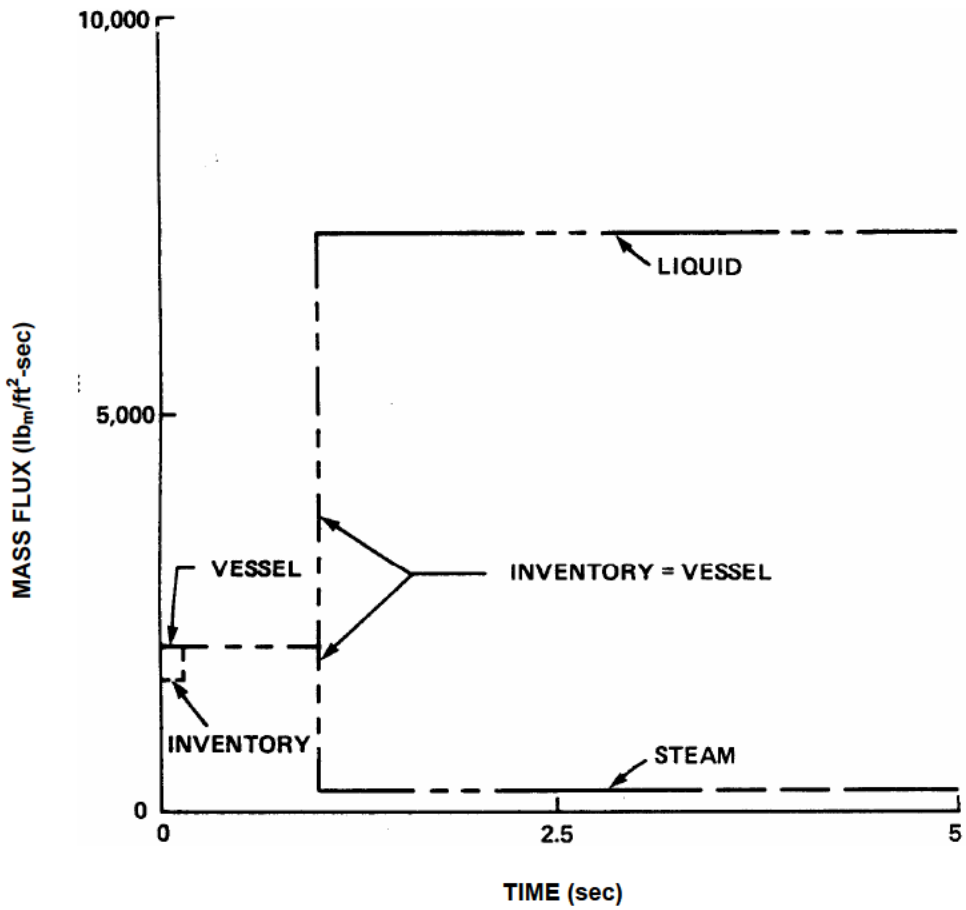
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
RHR DISCHARGE

FIGURE 6A-51

		INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)			
$0 \le t \le 0.135$		1620	2160
$0.135 < t \le 1.0$		2160	2160
$1.0 < t \le 5.0$	steam	300	300
	liquid	7280	7280



The recirculating (inlet and outlet) and the feedwater line breaks are the most limiting breaks and the effect of increase in mass and energy release for the main steam line break is bounded by the recirculating and feedwater line breaks.

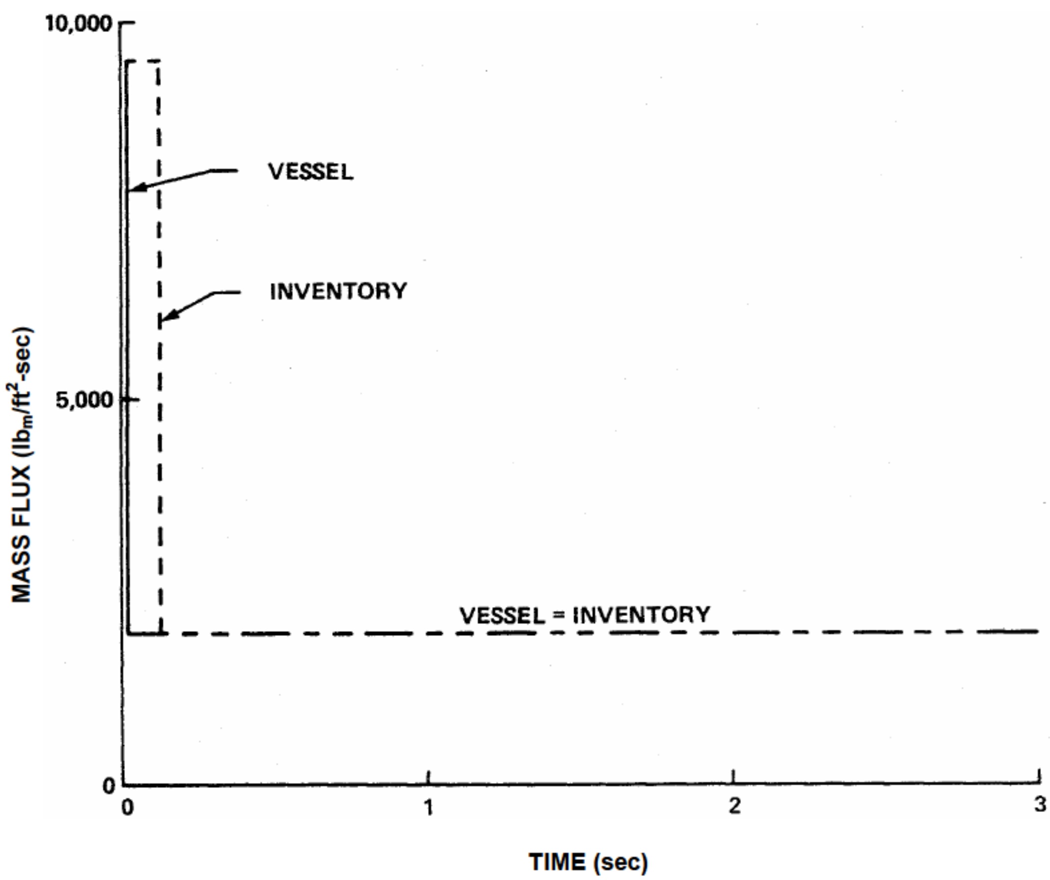
REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
MSLB, UPPER AND LOWER DRYWELL

FIGURE 6A-52

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)		
$0 \leq t \leq 0.0998$ sec.	9467	9467
$0.0998 < t \leq 0.131$ sec.	9467	2000
$0.131 < t \leq 3.0$ sec.	2000	2000



The results of the analysis for the main steam condensate drain line break are bounded by the recirculation line break and were not reevaluated for extended power uprate, thermal power optimization, and reactor operating pressure increase.

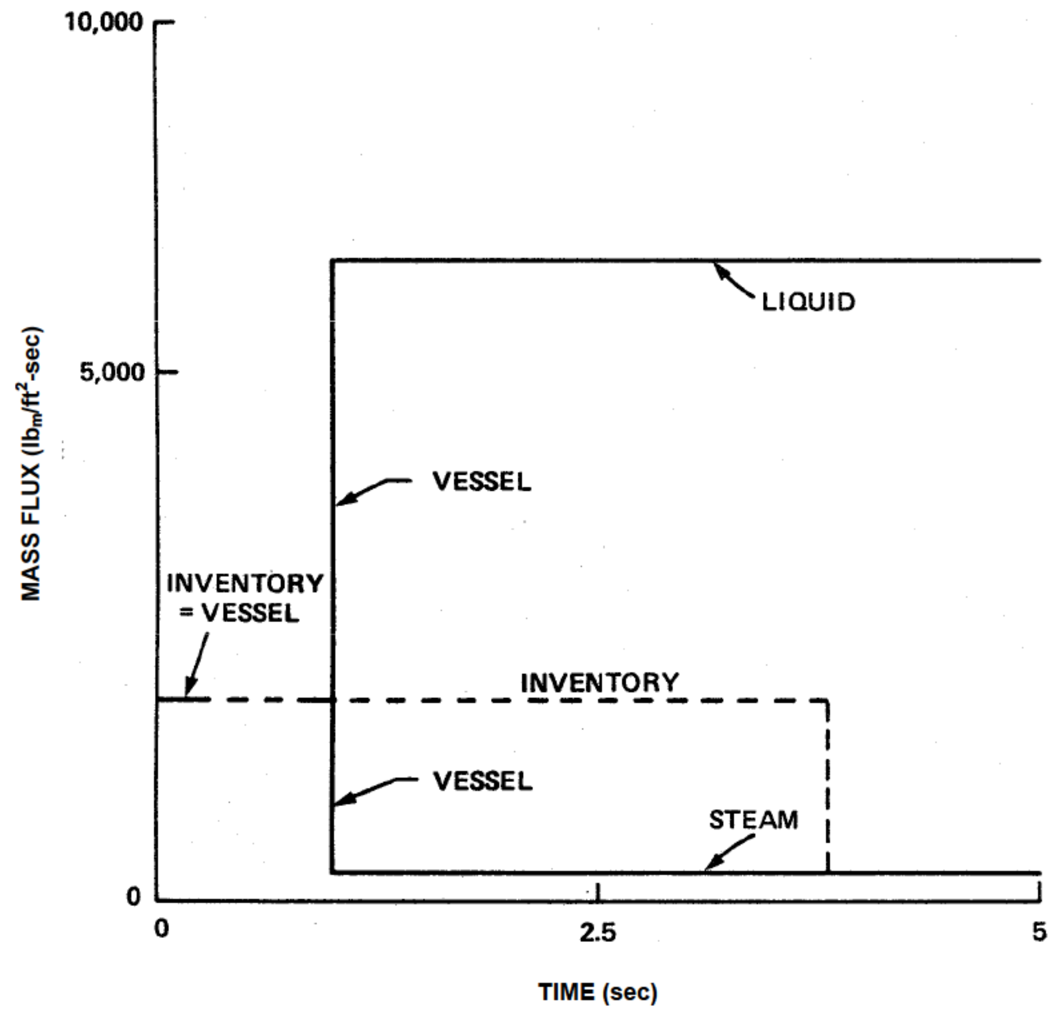
REV 22 9/04

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
MAIN STEAM CONDENSATE DRAIN

FIGURE 6A-53

		INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)			
$0 \le t \le 1$ sec.		2160	2160
$1 < t \le 3.8$ sec.		2160	-
$1 < t \le 5.0$ sec.	steam	–	300
	liquid	–	7280



REV 19 7/01

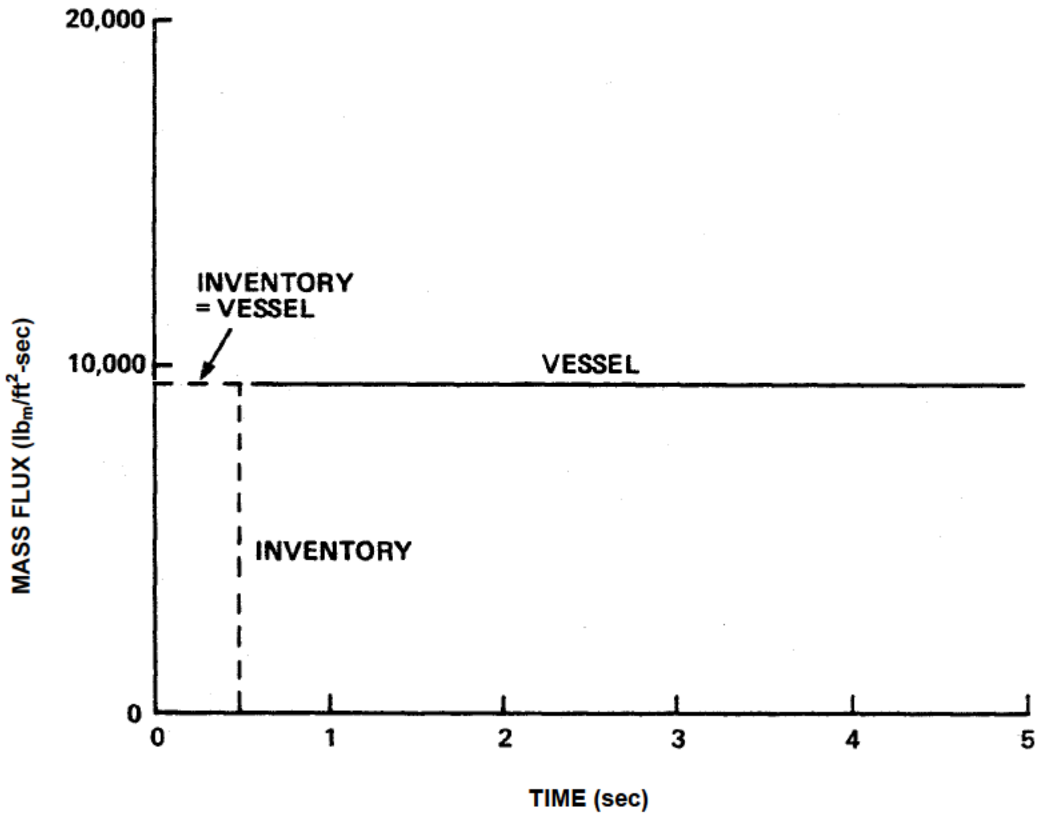
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MASS FLUX VS TIME
RCIC STEAM

FIGURE 6A-54

	INVEN.	VESSEL
MASS FLUX (lb_m/ft^2 – sec)		
$0 \leq t \leq 0.452$ sec.	9467	9467
$0.452 < t \leq 5.0$ sec.	0	9467

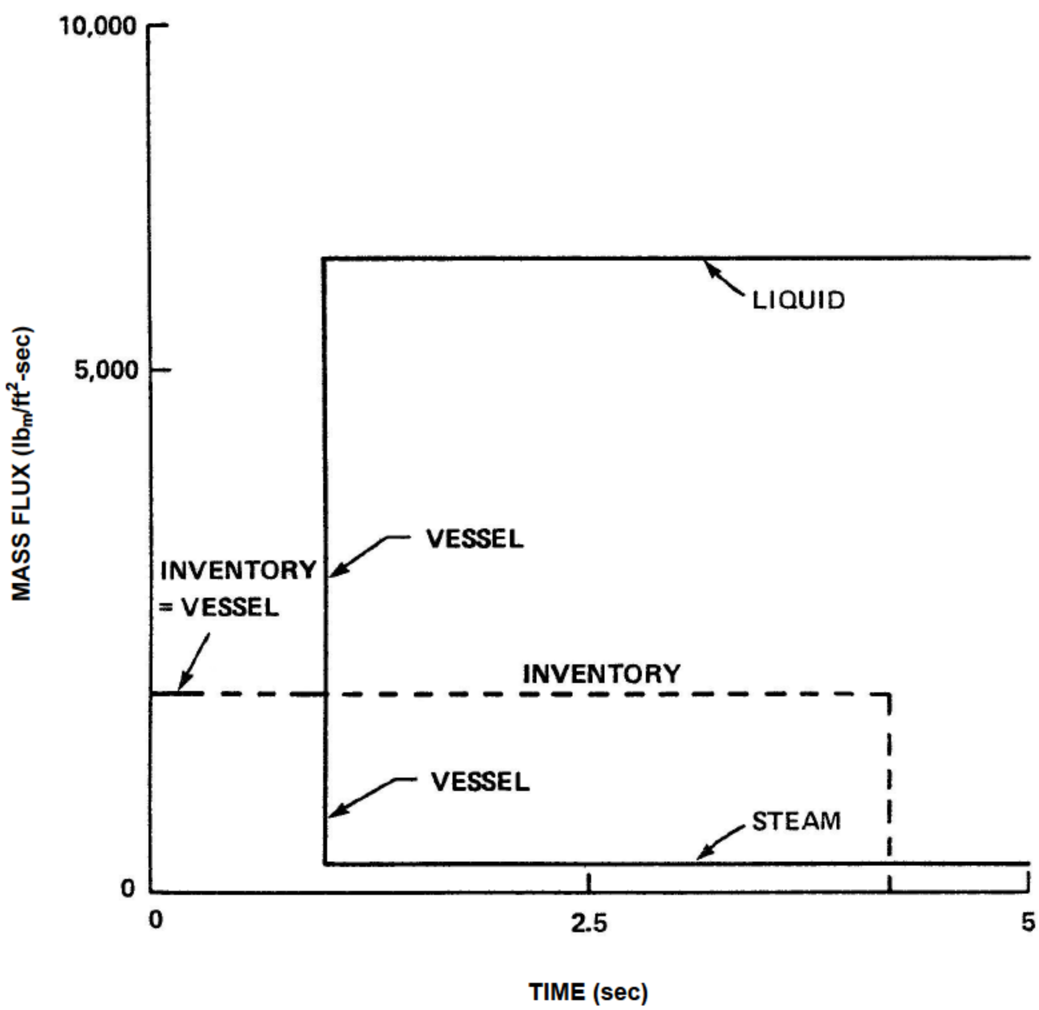


REV 19 7/01

MASS FLUX VS TIME
RWC

FIGURE 6A-55

MASS FLUX (lb_m/ft^2 – sec)		INVEN.	VESSEL
$0 \le t \le 1.0$ sec.		2160	2160
$1.0 < t \le 4.19$ sec.		2160	-
$1.0 < t \le 5.0$ sec.	steam	–	300
	liquid	–	7280

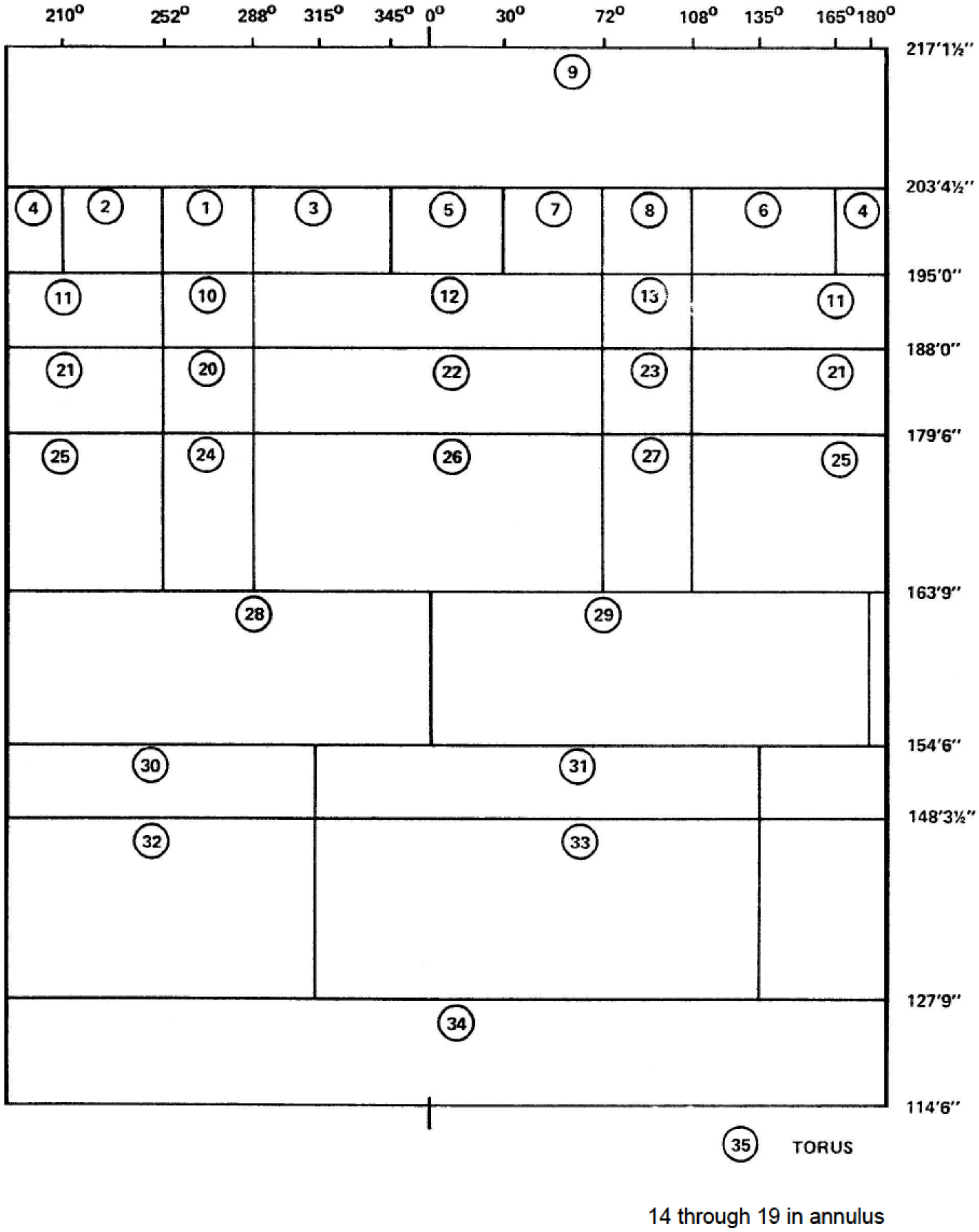


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

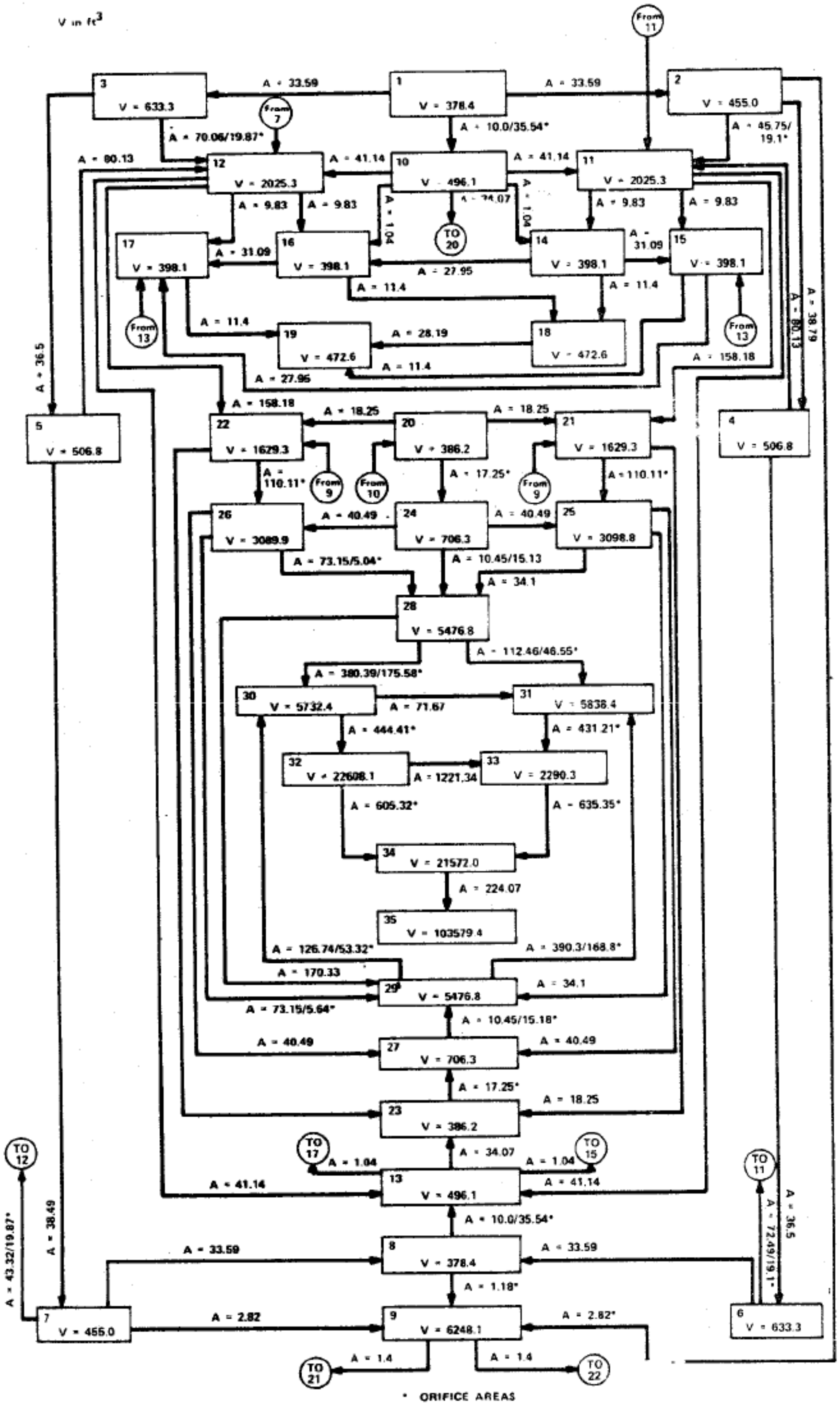
MASS FLUX VS TIME
HPCI STEAM

FIGURE 6A-56



210°
252°
288°
315°
345°
0°
30°
72°
108°
135°
165°
180°
217'1½"
203'4½"
195'0"
188'0"
179'6"
163'9"
154'6"
148'3½"
127'9"
114'6"
9
4
2
1
3
5
7
8
6
4
11
10
12
13
11
21
20
22
23
21
25
24
26
27
25
28
29
30
31
32
33
34
35
TORUS
14 through 19 in annulus

REV 19 7/01



REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

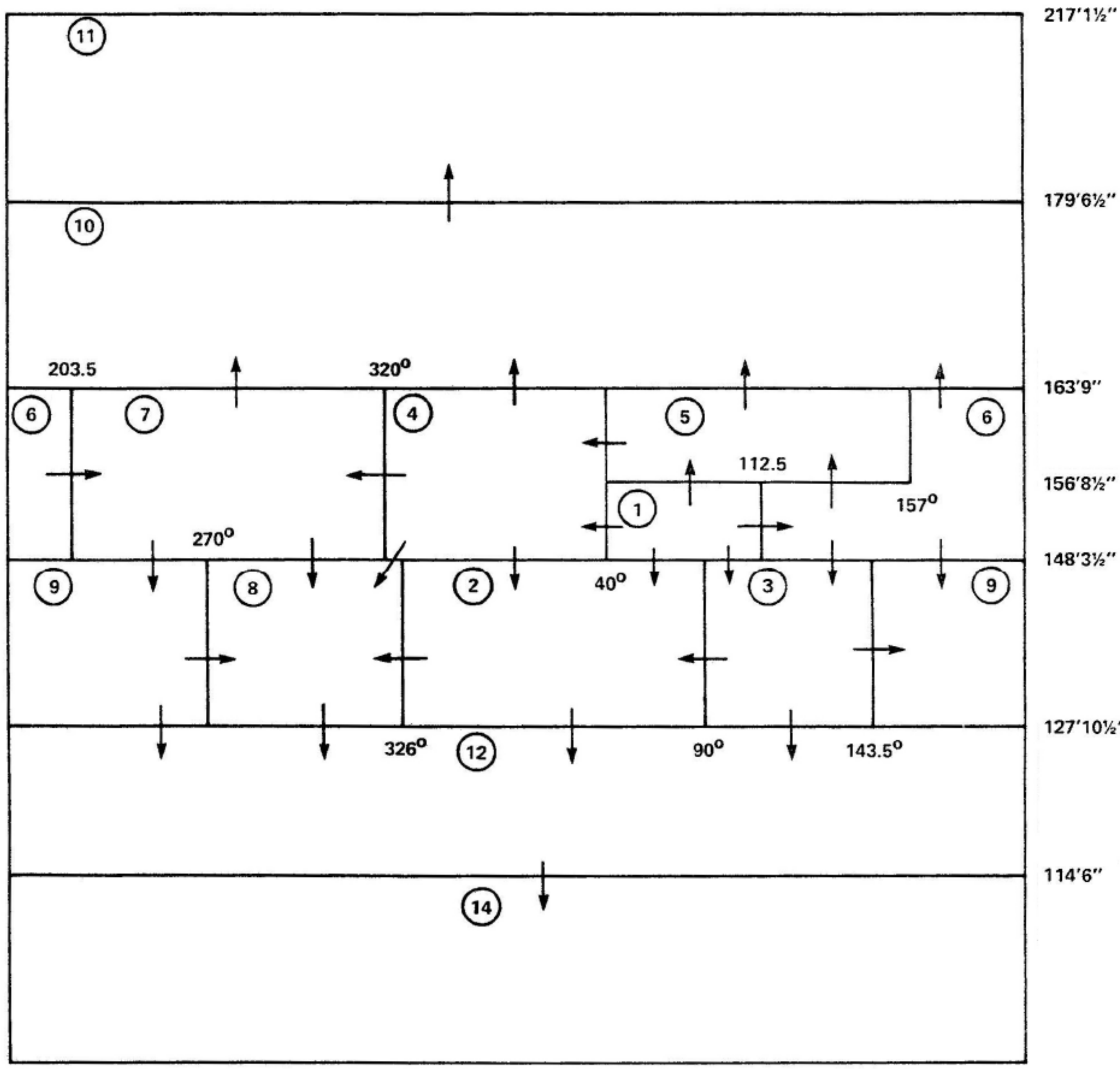
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC FLOW DIAGRAM FOR MSLB

FIGURE 6A-58

RHRDB2

180°



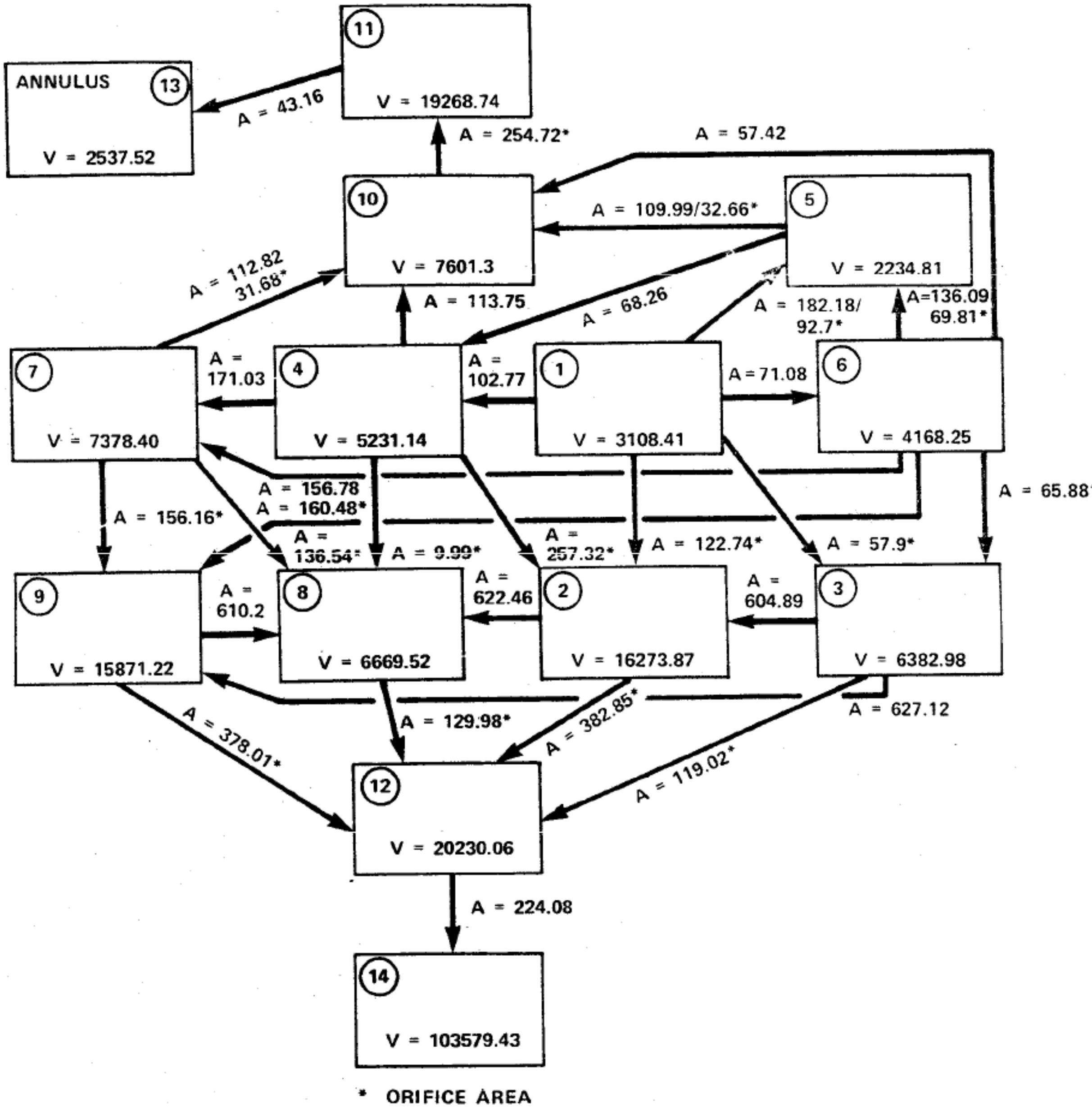
13 BETWEEN RPV AND SAC SHIELD

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NODE LOCATION FOR
RHR DISCHARGE LINE BREAK

FIGURE 6A-59

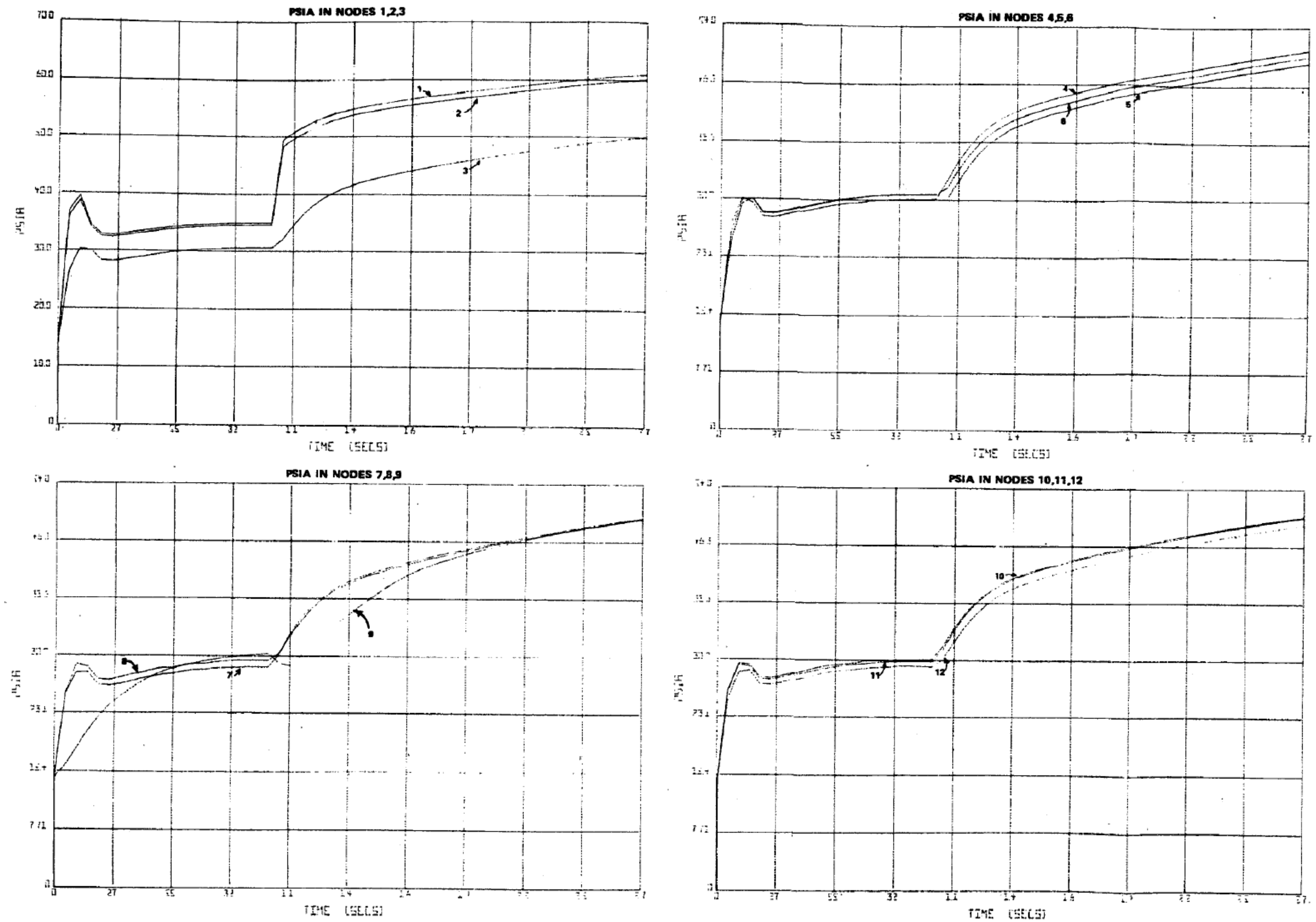


REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SCHEMATIC FLOW DIAGRAM FOR
RHR DISCHARGE LOWER DRYWELL

FIGURE 6A-60



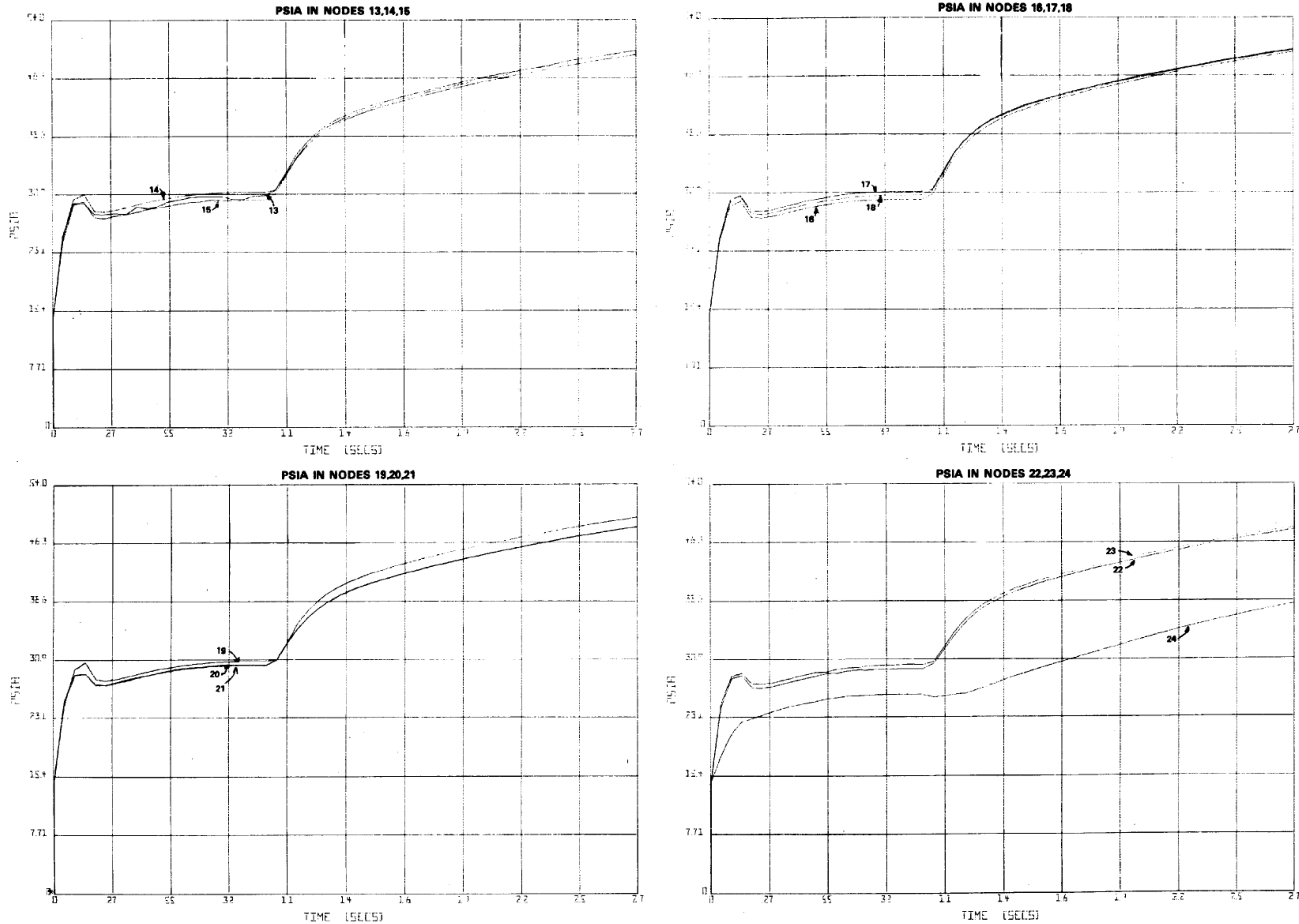
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

UPPER DRYWELL MSLB
PRESSURE IN NODES 1 – 12

FIGURE 6A-61 (SHEET 1 OF 3)



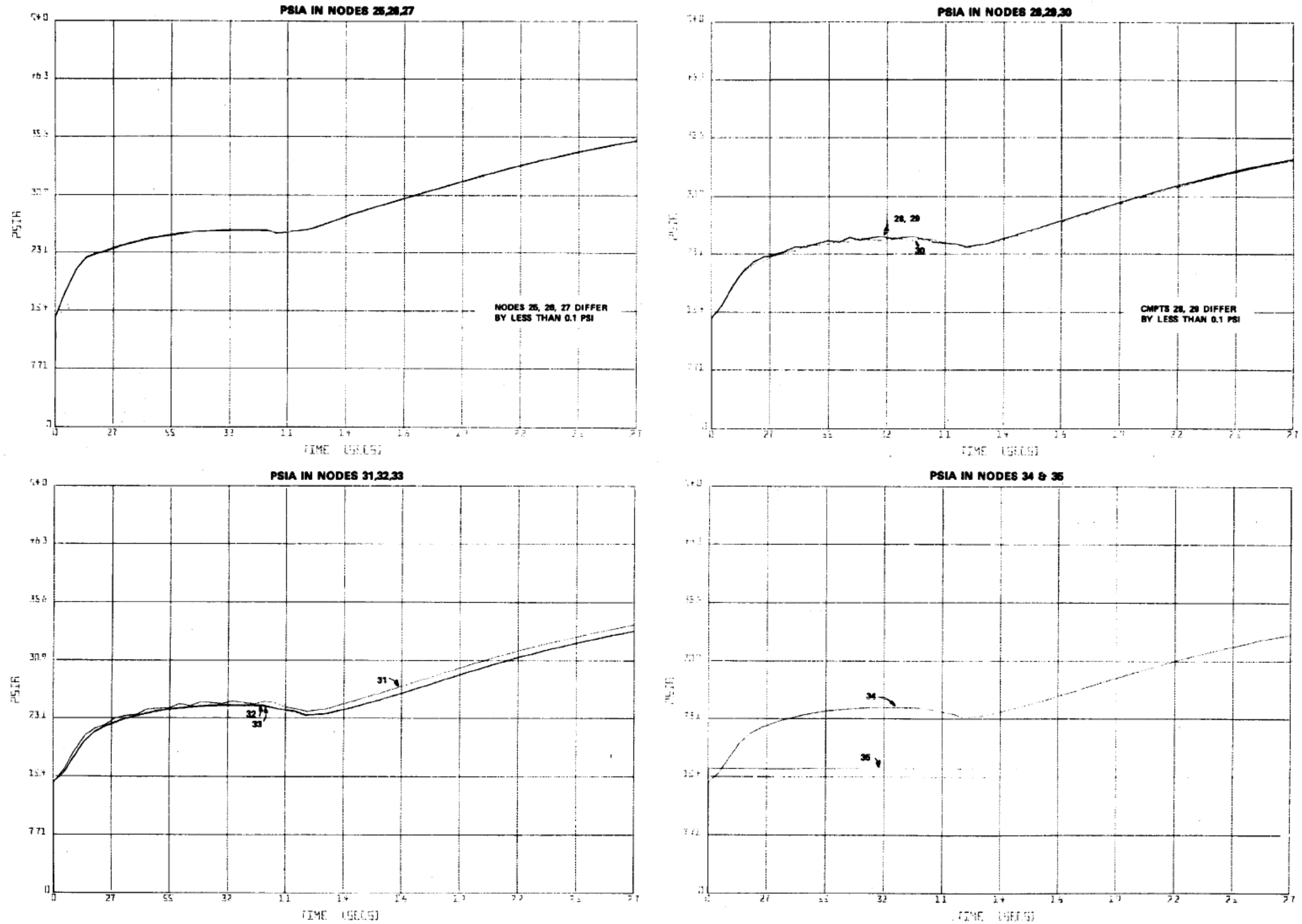
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

UPPER DRYWELL MSLB
PRESSURE IN NODES 13 - 24

FIGURE 6A-61 (SHEET 2 OF 3)



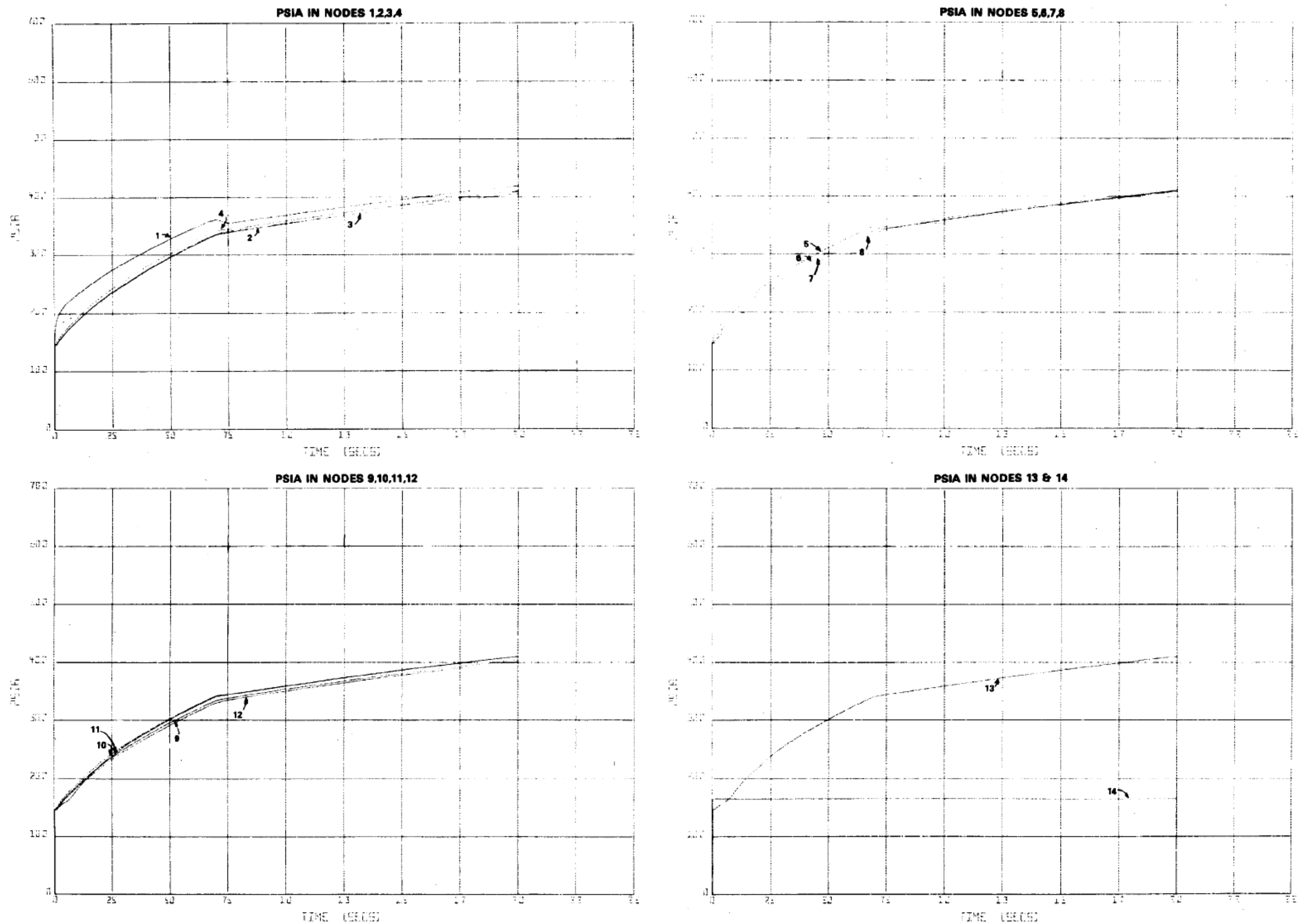
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

UPPER DRYWELL MSLB
PRESSURE IN NODES 25-35

FIGURE 6A-61 (SHEET 3 OF 3)



REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LOWER DRYWELL RHR DISCHARGE LINE BREAK
PRESSURE IN NODES 1 - 14

FIGURE 6A-62

7.0 INSTRUMENTATION AND CONTROL

7.1 INTRODUCTION

7.1.1 IDENTIFICATION AND CLASSIFICATION OF SAFETY-RELATED AND POWER GENERATION SYSTEMS

Depending on their functions, instrumentation and control systems may be classified as either power generation systems or safety systems. In some cases, portions of a system may have a safety function while other portions of the same system may be classified as power generation. Those systems with a safety or safety/power generation design basis or those systems whose control function could affect reactor operation are discussed in this chapter. Those systems are grouped as part of the reactor protection system (RPS), engineered safety features (ESFs) systems, safe shutdown systems, other safety and power generation systems, or control systems not required for safety. Table 7.1-1 lists the Edwin I. Hatch Nuclear Plant-Unit 2 (HNP-2) safety-related instrumentation, control, and supporting systems. Instrumentation and control systems identical to those of nuclear power plants of similar design are identified in table 7.1-2. Table 7.1-3 shows the interrelation between safety systems and supporting systems.

Power generation systems and safety systems may have both a safety design basis and a power generation design basis, depending on their functions. The safety design basis states in functional terms the unique design requirements that establish limits for the operation of the system. The general functional requirements portion of the safety design basis are those requirements that have been determined to be sufficient to ensure the adequacy and reliability of the system from a safety viewpoint. Many of these requirements have been introduced into various codes, criteria, and regulatory requirements.

7.1.1.1 Safety-Related Systems

Safety systems are those systems whose actions are necessary to protect the integrity of the fuel and reactor coolant pressure boundary and/or prevent the release of radioactive material. These systems may be components, groups of components, or groups of systems. A complete list of these systems is shown in table 7.1-1. The following systems have either a safety design basis or a safety and power generation design basis.

7.1.1.1.1 Basic Safety Systems

A. Reactor Protection System

RPS instrumentation and control initiates an automatic reactor shutdown (scram) if monitored system variables exceed pre-established limits. This action prevents fuel damage, limits system pressure, and thus, restricts the release of radioactive material.

B. Emergency Core Cooling System (ECCS)

ECCS instrumentation and control provides initiation and control of specific core cooling systems, such as the high-pressure coolant injection (HPCI) system, the automatic depressurization system (ADS), the core spray (CS) system, and the low-pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system.

C. Primary Containment and Reactor Pressure Vessel (PC/RPV) Isolation System

The PC/RPV isolation control system initiates closure of various automatic isolation valves in response to a limiting value of a system variable. The closure of isolation valves enables containment of radioactive material either inside the RPV or inside the primary containment. The system responds to various indications of pipe breaks or radioactive material release.

D. Reactor Core Isolation Cooling (RCIC) System

RCIC system instrumentation and control causes the addition of makeup water to the RPV in the event the reactor becomes isolated from the main condensers during plant operation by a closure of the main steam isolation valves (MSIVs).

E. Standby Liquid Control System (SLCS)

SLCS instrumentation and control provides for manual initiation of a redundant reactivity control system, which can shut down the reactor from rated power to the cold condition if withdrawn control rods cannot be inserted to achieve reactor shutdown.

As part of the implementation of an alternative source term (AST) (reference subsection 15.1.11), a new design function was added for SLCS to buffer the suppression pool by injection of a sufficient amount of sodium pentaborate solution to the suppression pool to prevent iodine re-evolution following a LOCA.

F. Residual Heat Removal System

RHR system instrumentation and control provides for manual initiation of cooling to remove the decay and sensible heat from the reactor vessel so the reactor can be refueled and serviced.

G. Suppression Pool Cooling Mode of RHR

RHR system instrumentation, valving, and controls are aligned so that suppression pool water is circulated through the RHR heat exchangers. Heat is removed by the residual heat removal service water (RHRSW) system. This system is discussed in subsection 6.2.2.

H. Main Control Room Environmental Control (MCREC) System

MCREC instrumentation and control maintains the environment of the MCR and provides for automatic pressurization in the event of high radiation in the intake air.

I. Standby Gas Treatment System (SGTS)

The SGTS is automatically initiated in the event of refueling floor or reactor building isolation to assure a negative pressure on the secondary containment.

J. Containment Spray Mode of RHR

As part of the implementation of an alternative source term (AST) (reference subsection 15.1.11), containment spray mode is now credited to remove airborne particulates in the drywell and to reduce the temperature and pressure of the primary containment atmosphere post-LOCA.

7.1.1.1.2 Auxiliary Supporting Systems

A. Plant Service Water (PSW)

PSW instrumentation and control ensures continuous availability of cooling water to essential services.

B. Residual Heat Removal Service Water System

RHRSW system instrumentation and control provides for manual initiation of cooling water to remove heat from the RHR heat exchangers.

C. Diesel Generator Auxiliary Systems

The diesel generator auxiliary systems include the fuel oil, cooling, starting, and lubricating subsystems, which are discussed in subsections 9.5.4 through 9.5.7.

D. dc Power System

The dc power system supplies control power for systems throughout the plant and is described in subsection 8.3.2.

E. RPV Instrumentation - Initiating Signals

Sensors are used to measure RPV water level and drywell pressure as discussed in paragraph 7.3.1.2. These signals initiate the various ECCS subsystems under LOCA conditions and provide permissive information, which is essential to correct system operation.

F. Suppression Pool

The suppression pool provides a transient heat sink to handle emergency shutdown conditions and also serves as a major reserve coolant source for the ECCS. The suppression pool design is discussed in paragraph 6.2.1.2.

G. ac Power System

The normal ac power system, including the standby ac power system, is described in subsection 8.3.1.

H. ECCS Room Coolers

The reactor building ECCS room coolers are part of the reactor building cooling system discussed in subsection 9.4.2.

7.1.1.1.3 Other Systems Important to Safety

A. Neutron Monitoring System (NMS)

NMS instrumentation and control uses incore neutron detectors to monitor core neutron flux. The NMS provides signals to the RPS to shut down the reactor when an overpower condition is detected. High average neutron flux is used as the overpower indicator during power operation. Intermediate range detectors are used as overpower indicators during startup and shutdown. The NMS also provides power level indication during planned normal operation. The rod block monitor (RBM) is integral with the NMS.

B. Refueling Interlocks

The refueling interlocks instrumentation and control serves as a backup to procedural core reactivity control during refueling operations.

C. Process Radiation Monitoring System (PRMS)

The PRMS provides control of radioactive material released from the Hatch site.[a] The main steam line radiation monitors detect gross release of fission products from the fuel and provide a trip signal resulting in isolation of the following:

- Drywell-to-torus differential pressure valve.
- Two reactor water sample valves.

---

a. The essential monitors are the main steam line, refueling floor ventilation, and reactor building ventilation radiation monitors.

- Main condenser mechanical vacuum pump.
- Steam packing exhauster.

The reactor building and refueling floor radiation monitors detect release of radiation from the secondary containment and provide a trip signal resulting in containment isolation and SGTS initiation.

D. Post-Accident Tracking

Process instrumentation provides information to the operator following an accident as described in paragraph 7.5.1.3.2.

E. Leak Detection System (LDS)

The LDS instrumentation and control uses various temperature, pressure, and flow sensors to detect, annunciate, and isolate (in certain cases) water and steam leakages in selected reactor systems.

F. Deleted

G. Deleted

H. Jockey Pump System

This system is provided to keep ECCS lines filled with water as described in paragraph 6.3.2.2.5.

I. Control Building Ventilation System

Part of this system consists of exhaust fans for the control building battery rooms as discussed in paragraph 9.4.7.2.6.

J. Remote Shutdown

This system is provided for shutting down the plant from outside the MCR as discussed in paragraph 7.5.1.4.2.

K. Containment Vacuum Relief System

This system consists of drywell-to-suppression pool vacuum breakers and suppression pool-to-secondary containment vacuum breakers. These systems are discussed in paragraph 6.2.1.2.

L. Recirculation Pump Trip (RPT)

This system consists of turbine control and stop valve closure sensors, reactor power level sensors, separate division logics, and four Class 1E circuit breakers to interrupt power to the recirculating pumps as discussed in subsection 5.5.16.

M. Low-Low Set Relief Logic System

The LLS relief logic system is designed to mitigate the postulated thrust loads on the safety relief valve discharge lines (SRVDLs) and the effects of postulated high-frequency loads on the torus shell caused by subsequent actuations of the SRVs during a small- or intermediate-break LOCA. This system is discussed in subsection 5.5.17.

7.1.1.2 Power Generation Systems

Power generation systems are systems whose actions are not required to protect the integrity of radioactive material barriers and/or prevent the release of radioactive material. The instrumentation and control portions of these systems may, by their actions, prevent the plant from exceeding preset limits, which would cause action of the safety systems. A complete list of these systems is shown in table 7.1-1.

A. Recirculation Flow Control System (RFCS)

RFCS instrumentation and control controls the reactor recirculation pumps and adjustable speed drives (ASDs) to vary the coolant flowrate through the core. This system was originally designed to permit either manual or automatic control. However, at Plant Hatch, only manual control is used since the automatic load-following capability is disconnected.

B. Feedwater Control System

The feedwater system instrumentation and control regulates the feedwater system flowrate so that proper reactor vessel water level is maintained. The feedwater system controller uses reactor vessel water level, main steam flow, and feedwater flow signals to regulate feedwater flow. The system is arranged to permit single-element (level only), three-element (level, steam flow, feed flow), or manual operation.

C. Pressure Regulator and Turbine-Generator Control

Pressure regulator and turbine-generator instrumentation and control work together to allow proper generator and reactor response to recirculation flow changes. The pressure regulator acts to keep nuclear system pressure essentially constant so that pressure-induced core reactivity changes are controlled. To maintain constant pressure, the pressure regulator adjusts the turbine control valves or turbine bypass valves. The turbine-generator controls keep turbine speed constant. If the

generator electrical load is lost, the turbine-generator speed-load controls initiate rapid closure of the turbine control valves (coincident with fast opening of the bypass valves) to prevent excessive turbine overspeed.

D. Reactor Water Cleanup (RWC)

RWC system instrumentation and controls provide for manual initiation of system equipment to maintain high water purity and reduce concentrations of fission products in the reactor water.

E. Reactor Manual Control System (RMCS)

RMCS instrumentation and control allows the operator to manipulate control rods and to determine their positions. Various interlocks are provided in the control circuitry to prevent multiple operator errors or equipment malfunctions from requiring the action of the RPS.

F. RPV Instrumentation (Nonessential)

RPV instrumentation monitors and transmits information concerning key reactor vessel operating variables.

7.1.2 IDENTIFICATION OF SAFETY AND POWER GENERATION CRITERIA

Design bases and criteria for instrumentation and control equipment design are based on the need to have the system perform its intended function while meeting requirements of applicable general design criteria, regulatory guides, and industry standards.

The plant instrumentation and control systems are listed by functional classification and regulatory classification in table 7.1-1. All systems have been examined with respect to specific regulatory requirements applicable to the instrumentation and control. These regulatory requirements consist of all applicable industry codes including 10 CFR 50 Appendix A, General Design Criteria; 10 CFR 50 Appendix B, Quality Assurance Criteria; and Nuclear Regulatory Commission (NRC) Regulatory Guides.

As a result of this examination, it was determined that two Institute of Electrical and Electronic Engineers (IEEE) standards are applicable to the instrumentation and control associated with every safety-related system: IEEE 344-1971 and IEEE 323-1971. Compliance with the requirements of IEEE 323-1971 and IEEE 344-1971 for General Electric Company (GE)-supplied systems is discussed in sections 3.11 and 3.10, respectively. Compliance for Bechtel-supplied systems is discussed in section 3.11, and supplements 3.7A and 3.7A.A.

7.1.2.1 Design Bases

IEEE 279-1971 defines the design requirements with respect to the design bases of safety-related systems. Using the IEEE 279-1971 format, the following fulfill these requirements:

A. The generating station conditions that require protective action include:

- Excessive radioactive material releases to the atmosphere.
- Excessive nuclear system stress.
- Excessive containment stress.

B. The generating station variables that require monitoring to provide protective actions include:

- RPV pressure.
- RPV water level.
- Reactor coolant temperature.
- Drywell temperature.
- Drywell pressure.
- Containment pressure.
- Release point radiation level.
- Neutron flux.
- Reactor coolant flow.

C. Minimum number of sensors and locations required to monitor safety-related variables is shown in tables 7.2-2, 7.2-3, 7.3-5, 7.3-6, 7.3-7, and 7.3-8.

D. Range of energy supply and environmental conditions of safety systems is discussed in section 3.11.

E. Malfunctions, accidents, and other unusual events that could cause damage to safety systems are discussed in subsections 7.2.2 and 7.3.2.

F. Minimum performance requirements are shown in tables 7.2-2, 7.2-3, and 7.3-5 through 7.3-8.

7.1.2.2 Independence of Redundant Safety-Related Systems

The criteria for the separation of safety-related electrical equipment are discussed in paragraph 8.3.1.4.1. The independence of redundant safety-related systems satisfies the applicable requirements of IEEE 279-1971. The requirements of 10 CFR 50 Appendix B are met in the manner set forth in chapter 17.

7.1.2.3 Physical Identification of Safety-Related Equipment

Equipment associated with the RPS, the PC/RPV isolation system, the ECCS, and the auxiliary electrical equipment associated with these systems are identified so that it is apparent:

A. The equipment is part of the RPS, PC/RPV isolation system, or the ECCS.

B. The particular equipment item is associated with a grouping (or division) of enforced segregation.

The identification consists of marking panels and equipment racks of the RPS, PC/RPV isolation system, ECCS, and auxiliary power systems with marker plates that are conspicuously different in color from those for other panels or racks. These markers include identification of the proper division of the equipment within the system.

The equipment identification number and the applicable segregation code, both numerical and color code, are applied to each piece of safety-related equipment either before or during that equipment's installation. A detailed discussion of the color codes used is provided in paragraph 8.3.1.5 and table 8.3-15.

7.1.2.4 Conformance to IEEE 317-1972

Compliance with IEEE 317-1972 is done for both qualification of the penetration assembly and the electrical services associated with it. Power cables are provided with reliable decoupling devices at their load centers to ensure fault interruption prior to any penetration damage. All cables having safety-related functions are separated from their redundant counterparts in different penetration assemblies.

7.1.2.5 Conformance to IEEE 323-1971

Compliance with IEEE 323-1971, IEEE Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations, is discussed in section 3.11.

Written procedures and responsibilities are developed for the design and qualification of all Class I electric equipment.

This includes preparation of specifications, qualification procedures, and documentation for Class I equipment, both manufactured and purchased by GE's boiling water reactor (BWR) systems department. Qualification testing or analysis is accomplished prior to release of the engineering design for production. Standards manuals are maintained containing specifications, practices, and procedures for implementing qualification requirements, and an auditable file of qualification documents is available for review.

7.1.2.6 Conformance to IEEE 336

HNP-2 complies with IEEE 336-1971, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations, except as modified by Southern Nuclear Operating Company procedures.

HNP-2 complies with IEEE 336-1985, as described in the SNC Quality Assurance Topical Report (QATR).

7.1.2.7 Conformance to IEEE 338-1971

For a detailed description of conformance, see the analysis portions of sections 7.2, 7.3, 7.4, and 7.6.

The PSW system, RHRSW system, and SGTS meet the requirements of IEEE 338-1971. The SLCS meets all the requirements of IEEE 338, except Sections 5.1 and 5.2. The SLCS squib valves cannot be actuated, without destruction, during reactor operation or shutdown. Therefore, continuity of the squib valves is monitored, and alarms are provided if continuity is lost.

7.1.2.8 Conformance to IEEE 344-1971

All instrumentation and control components of the SGTS that provide any safety function or action meet the requirements of IEEE 344-1971.

All instrumentation and control components of the PSW system that provide a safety function or action meet the requirements of IEEE 344-1971.

7.1.2.9 Conformance to IEEE 379-1972

The design of the non-GE supplied safety-related instrumentation and control systems meets the requirements of IEEE 379-1972. The separation and redundancy requirements for these systems are presented in paragraphs 7.3.3.2.4, 7.3.4.2.2, 7.3.4.3, 7.3.5.2.4, 7.3.6.2.5, 7.6.4.4.2, 7.6.4.5.2.1, 7.6.4.6.2, and 9.2.7.4. All provisions of IEEE 379 are met for the following GE-supplied systems:

- RPS.
- Nuclear steam supply shutoff system.
- HPCI.
- CS.
- LPCI.
- ADS.
- RCIC.
- Average power range monitor (APRM).
- Intermediate range monitor (IRM).
- Essential PRMS (as described in subsection 7.6.3).
- LDS (portion related to system isolation circuitry).
- RPT system.

The design bases for the SLCS and the refueling interlocks do not require that these systems meet requirements of IEEE 379-1972. The SLCS is a redundant system to the normal control rod drive (CRD) system for the purpose of maintaining shutdown margin only. While the SLCS does have some redundancy; e.g., two discharge pumps and motors, two squib valves, and two divisional sources of emergency power, it is believed that a single sodium pentaborate storage tank and a single injection point into the reactor vessel are justified by the extremely low probability that the system would ever be required to function in response to normal control rod failure. As part of the implementation of an AST (reference subsection 15.1.11), a new design function was added for SLCS to buffer the suppression pool by injection of a sufficient amount of sodium pentaborate solution to the suppression pool to prevent iodine re-evolution following a LOCA. See paragraph 4.2.3.4.3 for how SLCS meets the applicable NRC criteria to perform this function.

The primary purpose of the refueling interlocks is to prevent an inadvertent reactor criticality condition occurring during refueling operations. The degree of redundancy built into this system is described in subsection 7.6.1. Full redundancy is not part of the design basis because of the backup features and operational procedures that are in force during refueling operations. Inadvertent criticality is primarily avoided by strict Technical Specifications, which are designed to control all fuel and control rod movements. The Technical Specifications also contain provisions for bypassing certain refueling interlocks; e.g., any number of control rods may be withdrawn provided all fuel has first been removed from the associated control cells. In the extremely unlikely event inadvertent criticality occurs during refueling operations, the IRM system will initiate a scram. The IRM system is continuously available if a control rod is

withdrawn from a core cell containing one or more fuel assemblies. A radioactivity release is not associated with such an event.

7.1.2.10 Conformance to Regulatory Guide 1.22

A detailed description of conformance to Regulatory Guide 1.22 is furnished in sections 7.2, 7.3, 7.4, and 7.6.

The PSW system, RHRSW system, and SGTS meet the requirements of Regulatory Guide 1.22 (February 1972).

Actuated equipment that is not tested during reactor operation is as follows:

A. Reactor Building Closed Cooling Water (RBCCW) System Containment Penetration Inlet and Outlet Isolation Valves

   These valves are not closed during reactor operation since their closure would interrupt cooling water flow to the reactor recirculation pump seals, which will cause reactor recirculation pump seal failure and damage to the reactor recirculation pumps.

B. Main Feedwater Check Valves

   These valves are not testable during reactor operation; however, the operators are testable since the valve will not close against the high-pressure flow in the feedwater line.

C. CRD Scram Discharge Valves

   These valves are not tested during reactor operation since operation of individual valves introduces unnecessary reactor reactivity transients, and operation of all scram valves concurrently causes loss of the unit generation function.

D. SLCS Explosive Valves

   All components of the SLCS are testable within the provisions of this guide except the squib-actuated discharge valves. Squib continuity is monitored continuously and alarmed if lost.

The actuated equipment, which is not tested during reactor operation, consists of valve designs, which are widely used in operating nuclear power stations and for which there is significant operating experience that demonstrates a low probability of failure in the interval between periodic tests. These valves, which are not tested during reactor operation, are tested at each refueling.

7.1.2.11 Conformance to Regulatory Guide 1.47

The provision for the status indication of the bypassed and inoperable portions of the safety systems and the degree of conformance of the status indication to the recommendations provided in Branch Technical Position EICSB 21 are provided in appendix A.

The HNP-2 design does meet the intent of this guide. Each GE-supplied safety system is provided with its own automatic annunciation system, which indicates system level bypasses but at the component level; e.g., logic power failure. The annunciators are located on the MCR benchboards.

7.1.2.12 Conformance to Regulatory Guide 1.53

The safety-related instrumentation and control systems, except for the SLCS, meet the requirements of this guide as indicated in the following paragraphs:

- PSW 9.2.1.4.
- RHRSW 9.2.7.5.
- SGTS 6.2.4.4, 7.3.6.2.5, 7.3.6.2.7, and 7.3.6.3.1.
- MCREC 7.3.5.2.4, 7.3.5.2.7, 7.3.5.3.1, and 9.4.1.3.

The SLCS does not meet the requirements of Section C.2 of this guide. Continuity checks are used for the monitoring of the squibs since they cannot be actuated.

Compliance with Regulatory Guide 1.53 is also presented in appendix A.

7.1.2.13 Conformance to Regulatory Guide 1.62

The safety-related instrumentation and control systems, with the exception of the PSW system, meet the requirements of this guide. The PSW system is a normally operating system; therefore, the requirements of this guide for manual initiation are not met.

Compliance with Regulatory Guide 1.62 is also presented in appendix A.

TABLE 7.1-1 (SHEET 1 OF 2)

INSTRUMENTATION AND CONTROL SYSTEMS CLASSIFICATION

Function Classification

I. Safety Design Basis Systems

A. Basic Safety System

RPS
PC/RPV isolation
ECCS
  HPCI
  ADS
  CS
  LPCI
Suppression pool cooling

MCREC
SGTS
RCIC
SLCS
Shutdown cooling

B. Auxiliary Supporting Systems
PSW
RHRSW
Diesel generator auxiliary
dc power
RPV instrumentation - initiating signals
Suppression pool
ac power
ECCS pump room coolers

C. Other Systems Important to Safety

Refueling interlocks
NMS, including RBM
PRMS

Regulatory Classification

I. RPS

II. ESF Systems

PC/RPV isolation
ECCS
  HPCI
  ADS
  CS
  LPCI
PSW

SGTS

III. Safe Shutdown Systems

RCIC
SLCS
Shutdown cooling
RHRSW
Suppression pool cooling
Diesel generator auxiliary
dc power
RPV instrumentation - initiating signals
Suppression pool
ac power
ECCS pump room coolers
LLS

IV. Other Safety and Power Generation Systems

Refueling interlocks
NMS, including RBM

TABLE 7.1-1 (SHEET 2 OF 2)

Function Classification	Regulatory Classification
C. (Continued)	IV. (Continued)
Post-accident tracking	PRMS
	Post-accident tracking
Post-LOCA gamma monitor	Post-LOCA gamma monitor
LDS	RWC
Containment spray	RPV instrumentation (nonessential)
Containment vacuum relief	LDS
Jockey pump	Containment spray
Control building ventilation	Containment vacuum relief
Remote shutdown	Jockey pump
RPT	Control building ventilation
LLS	RPT
II. Power Generation Design Basis Systems	V. Control Systems Not Required for Safety
RWC system	RMCS
RPV instrumentation (nonessential)	RFCS
Process computer	Feedwater control system
RMCS	Pressure regulator and turbine generator control system
RFCS	Process computer
Feedwater control system	
Pressure regulator and turbine generator control system	

TABLE 7.1-2 (SHEET 1 OF 2)

SIMILARITY TO LICENSED REACTORS

System	Plants With Operating Licenses	Similarity of Design
RPS	HNP-1 Dresden 2/3	Identical Functionally similar
PC/RPV isolation control system	HNP-1, Duane Arnold Vermont Yankee	Identical Functionally similar
ECCS	HNP-1, Duane Arnold	Identical
NMS	HNP-1 Duane Arnold	Identical Identical, except for system size
Refueling interlocks	HNP-1, Duane Arnold Dresden 2/3	Identical
RPV instrumentation	HNP-1 Dresden 2/3	Identical Same in function and requirements
PRMS	HNP-1	Identical
Area radiation monitoring system	HNP-1	Identical
Process computer	HNP-1, Vermont Yankee	Identical
RCIC system	HNP-1, Duane Arnold	Identical
SLCS	HNP-1, Dresden 2/3	Identical
RWC system	HNP-1, Duane Arnold	Identical
LDS	HNP-1, Duane Arnold	Similar
Shutdown cooling system	HNP-1, Duane Arnold	Identical
RFCS	HNP-1	Identical

TABLE 7.1-2 (SHEET 2 OF 2)

System	Plants With Operating Licenses	Similarity of Design
Feedwater control system	HNP-1	Functionally similar
Pressure regulator and turbine control system	HNP-1	Functionally similar
PSW	HNP-1	Similar
RHRSW	HNP-1	Identical
Standby power systems	HNP-1	Identical
Turbine-generator overspeed trips	HNP-1	Identical
Plant cooling	HNP-1	Functionally similar
SGTS	HNP-1	Functionally similar
LLS	Grand Gulf-1 HNP-1	Similar Identical

TABLE 7.1-3 (SHEET 1 OF 2)

SUPPORTING SYSTEMS FOR SAFETY SYSTEMS

Main Systems	Supporting Systems
LPCI, CS, RHR	Standby ac power 125-V-dc power system Water storage (passive) Space cooling system PSW system Jockey pump system
Shutdown cooling system	Standby ac power • Div II inside isolation valve. • Div I pumps and valves dc (battery) power Div I outside isolation valve Equipment cooling - pump seal coolers Heat exchangers - service water system Instrumentation - pressure, level, temperature sensors
ADS	125-V-dc power system Drywell pneumatic system (ADS valve accumulators only) Suppression pool
RPS	No supporting systems required
Refueling interlocks	RMCS
SLCS	Instrument air, demineralized water supply, and ac power Normal or standby ac power for actual operation
Primary containment atmospheric monitors	Essential power source
Essential PRMS	Essential power source
PC/RPV isolation	Normal ac supply Standby ac supply dc (battery) supply Air supply Initiating instrumentation - pressure, flow, temperature, level, and radiation sensors
NMS	120 V-ac RPS supply Flow measurement - recirculation

TABLE 7.1-3 (SHEET 2 OF 2)

Main Systems	Supporting Systems
LDS	Isolation valves Instrumentation - flow, temperature, radiation, and pressure sensors Valve operator power supplies Instrument logic Equipment area coolers
HPCI/RCIC	Space cooling Condensate storage Suppression pool 125 V-dc power
PSW	Normal or standby ac power
RHRSW	Normal or standby ac power
MCREC	Normal or standby ac power
SGTS	Normal or standby ac power
LLS	125 V-dc power Drywell pneumatic (LLS valve accumulators only) Suppression pool

7.2 REACTOR PROTECTION SYSTEM (RPS)

This section describes the RPS for the Hatch Nuclear Plant-Unit 2 (HNP-2). This system is identical to the HNP-1 RPS. There are no differences other than those of instrument panel locations within the plant.

7.2.1 DESIGN BASES

This subsection discusses the functional safety design bases of and regulatory requirements for the RPS. The RPS has no power generation objective. (The setpoints, instrumentation, and controls are arranged to preclude spurious scrams.) The scram functions for the RPS are shown in figure 7.2-1.

7.2.1.1 General Functional Requirements

The RPS is designed to:

- Initiate a reactor scram with precision and reliability to prevent or limit fuel damage following anticipated operational occurrences (AOOs).
- Initiate a scram with precision and reliability to prevent damage to the nuclear system process barrier as a result of excessive internal pressure; that is, to prevent nuclear system pressure from exceeding the limit allowed by applicable industry codes.
- Limit the uncontrolled release of radioactive material from the fuel or nuclear system process barrier, by precisely and reliably initiating a reactor scram upon gross failure of either of these barriers.
- Detect conditions that threaten the fuel or nuclear system process barriers by deriving inputs from variables that are true, direct measures of operational conditions.
- Respond correctly to the sensed variables over the expected range of magnitudes and rates of change.
- Provide adequate number of sensors for monitoring essential variables that have spatial dependence.
- Operate with sufficient reliability to ensure that:
    - If failure of a control or regulating system causes a plant condition that requires a reactor scram but also prevents action by necessary RPS channels, the remaining portions of the RPS meet the requirements of the first three items.

- Loss of one power supply neither causes nor prevents a reactor scram.

- Once initiated, an RPS action goes to completion. Return to normal operation requires deliberate operator action.

- There is sufficient electrical and physical separation between redundant instrumentation and control equipment monitoring the same variable to prevent environmental factors, electrical transients, or physical events from impairing the ability of the system to respond correctly.

- Earthquake ground motions, as amplified by building and supporting structures, do not impair the ability of the RPS to initiate a reactor scram.

- No single failure within the RPS prevents proper RPS action.

- Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability does not impair the ability of the RPS to respond correctly.

- There is a high probability that when the required number of sensors for any monitored variable exceeds the scram setpoint, the event results in an automatic scram and does not impair the ability of the system to scram as other monitored variables exceed their scram trip points.

- The operator has means independent of the automatic scram functions to counteract conditions that threaten the fuel or nuclear system process barrier, by manually initiating a reactor scram.

- The operator has the means to assess the condition of the RPS and to identify conditions that threaten the integrities of the fuel or nuclear system process barrier:

    -- The RPS provides the operator with information pertinent to the operational status of the protective system.

    -- The RPS provides prompt identification of channel and trip system responses.

- Permit verification of the operational availability of each channel and logic.

- Reduce the probability that RPS operational reliability and precisions are degraded by operator error by:

    - Placing access to trip settings, component calibration controls, test points, and other terminal points under the control of plant operations supervisory personnel.

  - Placing manual bypass of instrumentation and control equipment components under the control of the main control room (MCR) operator. If the ability to trip some essential part of the system has been bypassed, this fact is continuously indicated in the MCR.

- Provide physical identification of the RPS and engineered safety feature (ESF) equipment as safety equipment, as follows:

  - Equipment associated with the RPS, primary containment isolation system, and ESF is identified so that two facts are apparent: first, that the equipment is part of the RPS, primary containment isolation system, or the ESF system; and second, the grouping (or division) of enforced segregation with which the equipment is associated.

  - Panels and racks associated with these systems are labeled with marker plates which are conspicuously different from those of other similar panels by means of color, shape, or color of engraving fill. The information on the marker plate includes both system and division identification.

  - Junction and/or pull boxes enclosing wiring for the RPS, primary containment isolation system, and ESF have identification similar to and compatible with the panels and racks described above.

  - Wiring and cables outside cabinets and panels are suitably color-coded to identify both the system and division. Identification tags or markers for wiring conduits are conspicuously different from other similar tags and markers, and include both system and division identity.

  - Those trays or conduits which carry RPS, primary containment isolation system, and ESF system wiring are to be identified with conspicuous tags at entrance and exit points of each room through which they pass.

7.2.1.2 Regulatory Requirements

The RPS is designed to meet the following requirements:

A. Industry Standards

In addition to the previous functional design requirements, the RPS complies with the requirements of Institute of Electrical and Electronics Engineers (IEEE) 279-1971. A point-by-point comparison of IEEE 279-1968 is contained in NEDO-10139. Section 7.2.3 lists those topics where IEEE 279-1971 differs from IEEE 279-1968 and shows conformance to those differences. IEEE 338-1971 and IEEE 344-1971 also apply to the RPS. There are no anticipatory trips in the RPS.

B. General Design Criteria of Title 10 Code of Federal Regulations (CFR) Part 50

Criteria 13, 20 through 24, and 29 of 10 CFR 50, Appendix A have also been implemented in the design of the RPS.

C. Regulatory Guide

Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Function," applies with respect to periodic testing.

7.2.2 DESCRIPTION

7.2.2.1 System Identification and Classification

The RPS includes the motor-generator power supplies, sensors, relays, bypass circuits, and switches that cause rapid insertion of control rods (scram) to shut down the reactor. It also includes outputs to the process computer system and annunciators, although these latter two systems are not part of the RPS. Trip functions are summarized in figure 7.2-1. The RPS is classified as Safety Class 2, Seismic Category I, and Quality Group B.

7.2.2.2 Initiating Circuits

The following systems or sensors can initiate RPS action:

- Neutron monitoring system (NMS).
- Reactor pressure vessel (RPV) high pressure.
- RPV water level 3 trip.
- Turbine stop valve closure.
- Turbine control valve fast closure.
- Main steam line isolation valve closure.
- Scram discharge header high water level.
- Drywell high pressure.

Neutron Monitoring System

NMS instrumentation is described in subsection 7.6.2. Figure 7.2-2 clarifies the relationship between NMS channels, NMS logic, and RPS logic. The NMS channels are part of the NMS.

The NMS logic is part of the RPS. As shown in figure 7.2-3, there are four NMS logics associated with each trip system of the RPS. Each RPS logic receives inputs from two NMS logics. Each RPS logic receives signals from one intermediate range monitor (IRM) channel and one average power range monitor (APRM) voter channel. The position of the mode switch determines which input signals effect the output signal from the logic. The NMS logics are arranged so that failure of any one logic cannot prevent the initiation of a high neutron flux scram.

RPV Pressure

RPV pressure is measured at two locations. A pipe from each location is routed through the primary containment and terminates in the reactor building. Two local, rack-mounted, pressure transmitters monitor the pressure in each pipe. Cables from these transmitters are routed to the associated pressure-indicating switch (trip unit) located in the MCR. One pair of the transmitters/trip units is physically separated from the other pair. Each trip unit provides a high-pressure signal to one channel. The trip units are arranged so that two trip units provide an input to trip system A and two trip units provide an input to trip system B, as shown in figure 7.2-4. The physical separation and the signal arrangement ensure that no single physical event can prevent a scram caused by nuclear system high pressure. The RPV instrumentation mentioned above is part of the analog transmitter trip system (ATTS), which is discussed in section 7.8.

RPV Low Water Level

The RPV water level 3 signal is initiated from nonindicating-type differential pressure transmitters that sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual water level in the vessel. Cables from these transmitters are routed to the associated differential pressure-indicating switches (trip units) located in the MCR. The transmitters are arranged on two sets of taps in the same way as the nuclear system high-pressure transmitters (figure 7.2-4). Two instrument lines attached to taps on the reactor vessel, one above and one below the water level, are required for the differential pressure measurement for each transmitter. The two pairs of lines terminate outside the primary containment and inside the reactor building. They are physically separated from each other and tap off the RPV at widely separated points. Other systems sense pressure and level from these same pipes. The physical separation and signal arrangement ensure that no single physical event can prevent a scram due to reactor vessel low water level. The RPV water level instrumentation mentioned above is part of the ATTS, which is discussed in section 7.8.

Turbine Stop Valve Closure

Turbine stop valve closure inputs to the RPS come from valve stem position switches mounted on the four turbine stop valves. To provide the earliest positive indication of closure, each of the double-pole, single-throw switches opens before the valve is more than 10% closed. Either of the two channels associated with one stop valve can signal valve closure, as shown in figure 7.2-5. The logic is arranged so that isolation of three or four steam lines initiates a scram. Turbine stop valve closure can initiate a recirculation pump trip (RPT) whenever the first-stage turbine pressure is above that which corresponds to 27.6% of rated thermal power.

Turbine Control Valve Fast Closure

Control valve fast closure can initiate a scram whenever the first-stage turbine pressure is above that which corresponds to 27.6% of rated power. Turbine control valve fast closure inputs to the RPS come directly from the electrohydraulic control (EHC). Control valve fast closure can initiate an RPT whenever the first-stage turbine pressure is above that which corresponds to ~ 27.6% of rated thermal power.

Main Steam Line Isolation Signal

Position switches mounted on the eight main steam isolation valves (MSIVs) signal MSIV closure to the RPS. To provide the earliest positive indication of closure, each of the double-pole, single-throw switches is arranged to open before the valve is more than 10% closed. Either of the two channels associated with one isolation valve can signal valve closure. To facilitate the description of the logic arrangement, the position-sensing channels for each valve are identified and assigned to RPS logics as follows:

Valve Identification	Position-Sensing Channels	Trip Channel Relays	Assignment
Main steam line A, inboard valve	F022A (1) and (2)	A, B	A1, B1
Main steam line A, outboard valve	F028A (1) and (2)	A, B	A1, B1
Main steam line B, inboard valve	F022B (1) and (2)	E, D	A1, B2
Main steam line B, outboard valve	F028B (1) and (2)	E, D	A1, B2
Main steam line C, inboard valve	F022C (1) and (2)	C, F	A2, B1
Main steam line C, outboard valve	F028C (1) and (2)	C, F	A2, B1
Main steam line D, inboard valve	F022D (1) and (2)	G, H	A2, B2
Main steam line D, outboard valve	F028D (1) and (2)	G, H	A2, B2

Thus, each logic receives signals from the valves associated with two steam lines as shown in figure 7.2-6. The arrangement of signals within each logic requires closing of at least one valve in each of the steam lines associated with that logic to cause a trip of that logic. For example, closure of the inboard valve of steam line A and the outboard valve of steam line C causes a trip of logic B1. This in turn causes trip system B to trip. No scram occurs because no trips occur in trip system A. In no case does closure of two valves or isolation of two steam lines cause a scram due to valve closure. Closure of one valve in either three or four steam lines causes a scram.

Wiring for the position-sensing channels from one position switch is physically separated in the same way that wiring to duplicate sensors on a common process tap is separated. The wiring for position-sensing channels feeding the different trip logics of one trip system is also

separated. The MSIV closure scram function is effective only if the reactor mode switch is in RUN.

The effects of the logic arrangement and separation provided for the MSIV closure scram are as follows:

A. Closure of one valve for test purposes with one steam line already isolated does not cause a scram resulting from valve closure.

B. Automatic scram occurs on isolation of any three of the four steam lines.

C. No single failure can prevent an automatic scram required for fuel protection due to MSIV closure.

Scram Discharge Header

Four nonindicating float switches and four redundant and diverse thermal probes located in the reactor building provide scram discharge header high water level inputs to the RPS. Cables are routed from the thermal probes to switches located in the MCR. Each switch provides an input to one channel (figure 7.2-4). The switches are arranged so that no single event prevents a reactor scram caused by scram discharge volume high water level. The trip point for these switches cannot be significantly adjusted without physically cutting the switch out of the scram discharge volume and rewelding it at a different level. With the scram setting listed in table 7.2-1, a scram is initiated when insufficient capacity remains in the discharge volume to accommodate a scram. Both the amount of water discharged and the volume of air trapped above the free surface during a scram were considered in the selection of the trip setting.

Drywell High Pressure

Drywell pressure is monitored by four nonindicating pressure transmitters as described in subsection 7.6.4. Cables from the transmitters are routed to the associated pressure-indicating switches (trip units) located in the MCR. The transmitters/trip units are physically separated and electrically connected to the RPS so that no single failure can prevent a scram caused by primary containment high pressure. The drywell pressure instrumentation mentioned above is part of the ATTS, which is discussed in section 7.8.

7.2.2.3 Logic

The basic logic arrangement of the RPS is illustrated on drawing no. H-24728. The system is arranged as two separately powered trip systems. Each trip system has two logics, as shown in figure 7.2-7. The two logics are used to produce either automatic or manual trip signals. Each logic receives input signals from at least one channel for each monitored variable. At least four channels for each monitored variable are required, one for each of its four automatic logics.

Each logic provides two inputs into each of the actuator logics of one trip system, as shown on drawing nos. H-27612 and H-27613. Thus, either of the two automatic logics associated with one trip system can produce a trip-system trip. The logic is a one-out-of-two arrangement. To

produce a scram, the actuator logics of both trip systems must be tripped. The overall logic of the RPS is one-out-of-two-taken-twice.

7.2.2.4 Bypasses and Interlocks

Scram Bypass

A number of manual and automatic scram bypasses are provided. These account for the varying protection requirements that depend upon reactor conditions. They also allow for instrument service during reactor operations. All manual bypass switches are in the control room under the direct control of the MCR operator. The bypass status of trip system components is continuously indicated in the MCR.

The scram initiated by placing the mode switch in SHUTDOWN is automatically bypassed after a short time delay. The bypass allows the control rod drive (CRD) hydraulic system valve lineup to be restored to normal. An annunciator in the MCR indicates the bypassed condition. The turbine control valve fast closure scram and turbine stop valve closure scram are automatically bypassed if the turbine first-stage pressure is < 27.6% of its rated value. Closure of these valves from a low initial power level does not threaten the integrity of any radioactive material release barrier.

Turbine and generator trip bypass is effected by four pressure switches associated with the turbine first stage. Any one channel in a bypass state produces an MCR annunciation.

Bypasses for the NMS channels are described in subsection 7.6.2.

The scram discharge high water level trip bypass is controlled by the manual operation of two keylocked switches, a bypass switch, and the mode switch. The mode switch must be in either the SHUTDOWN or the REFUEL position. Four bypass channels emanate from the four banks of the RPS mode switch and are each connected into the RPS logic. This bypass allows the operator to reset the RPS scram relays so that the system is restored to operation while the operator drains the scram discharge header. In addition, actuating the bypass initiates a control rod block. Resetting the trip actuators opens the scram discharge header vent and drain valves. An annunciator in the MCR indicates the bypass condition.

The RPS reset switch is used to momentarily bypass the seal-in contacts of the final actuators of the reactor shutdown systems. These seal-in contacts are located downstream from the protection channel outputs. The reset is effected in conjunction with auxiliary relays. If a single channel is tripped, the reset is accomplished immediately upon operation of the reset switch. On the other hand, if a reactor scram situation is present, manual reset is prohibited for a 10-s period to permit the control rods to achieve their fully inserted position.

Interlocks

The scram discharge header high water level trip bypass signal interlocks with the reactor manual control system to initiate a rod block. The interlock is performed using isolated relay contacts so that no failure in the control system can prevent a scram.

Reactor vessel low water level and primary containment high-pressure signals are shared with the primary containment and reactor vessel isolation system. The sensors feed sensor relays in the RPS. Contacts from these relays interlock to the primary containment and reactor vessel isolation system.

7.2.2.5 Actuated Devices

The actuator logic opens when a trip signal is received and then deenergizes the scram valve pilot solenoids. There are two pilot solenoids per control rod. One solenoid receives its signal from trip system A and the other from trip system B. The failure of one control rod to scram does not prevent a complete shutdown.

The individual control rods and their controls are not part of the RPS. Further information on the scram valves and control rods is contained in subsection 4.2.3.

7.2.2.6 Redundancy, Diversity, and Separation

The RPS is divided into two divisions. Each division duplicates the function of the other to the extent that either may perform the required function regardless of the state of operation or failure of the other.

Functional diversity is provided by monitoring dependent reactor vessel variables. Pressure, water level, and neutron flux are all interdependent and are separate inputs to the system. Also, MSIV closure, turbine stop valve closure, and turbine control valve fast closure are anticipatory of a reactor vessel high pressure and are separate inputs to the system.

Four independent sensor channels monitor each of the various process variables listed in paragraph 7.2.2.2. Separation criteria are given in paragraph 8.3.1.4.1. The sensor devices are separated in such a way that no single failure can prevent a scram. All protection system wiring outside the control system cabinets is run in rigid metal conduit. Four physically separated cabinet bays are provided for the scram logics.

The mode switch, scram discharge volume high water level trip bypass switch, scram reset switch, and manual scram switch are all mounted on one control panel. Each device is mounted in a can and has a sufficient number of barrier devices to maintain adequate separation. Conduit is provided from the cans to the logic cabinets.

The outputs from the logic cabinets to the scram valves are run in four conduits for trip system A and four conduits for trip system B. The four conduits match the four scram groups shown on

drawing nos. H-24728 through H-24730. The groups are selected so that the failure of one group to scram does not prevent a reactor shutdown.

Wiring for the RPS, outside of the enclosures in the MCR, is run in rigid metallic conduits used for no other wiring. The wires from duplicate sensors on a common process tap are run in separate conduits. Wires from sensors of different variables in the same RPS logic can be run in the same conduit.

The scram pilot valve solenoids are powered from eight actuator logic circuits; four circuits from trip system A and four from trip system B. The four circuits associated with any one trip system are run in separate conduits.

Electrical panels, junction boxes, and components of the RPS are prominently identified by nameplate. Circuits entering junction boxes or pull boxes are conspicuously marked inside the boxes. Wiring and cabling outside cabinets and panels are identified by color, tag, or other conspicuous means.

7.2.2.7 Power Supply

The RPS receives power from two high-inertia ac motor-generator sets (drawing no. H-24728). A flywheel provides high inertia sufficient to maintain voltage and frequency within 5% of rated values for at least 1 s following a total loss of power to the drive motor.

Alternate power is available to reach the RPS buses. A manual transfer scheme is provided, which allows any one of the two RPS buses to be supplied from the 120-208-V-ac power system as shown in figure 8.3-9.

7.2.2.8 Testability

The RPS can be tested during reactor operation by any of the five following tests:

A. Manual Scram Test

   The first of these is the manual actuator test. By depressing one of the manual scram buttons for one trip system, the manual actuators are deenergized, opening contacts in the actuator logic. After the first trip system is reset, the second trip system is tripped with another manual scram button associated with that trip system. The total test verifies the ability to deenergize all eight groups of scram pilot valve solenoids by using the manual scram pushbutton switches. In addition to MCR and sequence recorder printout indications, scram group indicator lights verify that the actuator contacts have opened.

B. Automatic Actuator Test

   The second test is the automatic actuator test. It is accomplished by operating the keylocked test switches one at a time for each automatic logic. The switch

deenergizes the actuators for that logic and causes the associated actuator contacts to open. The test verifies the ability of each logic to deenergize the actuator logics associated with the parent trip system. In addition to annunciator and computer indications, the actuator and contact action can be verified by observing the physical position of these devices.

C. NMS Calibration Test

The third test includes calibration of the NMS by means of simulated inputs from calibration signal units. Subsection 7.6.2 describes the calibration procedure.

D. Control Rod Scram Test

The fourth test is the single rod scram test, which verifies capability of each rod to scram. It is accomplished by operating one toggle switch located in the MCR for the particular CRD. Timing traces can be made for each rod scrammed. If the test is conducted in Mode 1 or 2 below the Technical Specification low power setpoint for the rod worth minimizer, a physics review is conducted prior to the test to ensure that the rod pattern during scram testing does not create a rod of excessive reactivity worth. This physics review may involve the special CRDA analyses described in the Bases for Technical Specification 3.10.7.

E. RPS Test Signals

The fifth test involves applying a test signal to each RPS channel in turn and observing that a logic trip results. This test also verifies the electrical independence of the channel circuitry. The test signals can be applied to the process-type sensing instruments (pressure and differential pressure) through calibration taps.

The process computer alarm log and display can be used to verify the correct operation of many sensors during plant startup and shutdown. MSIV position switches can be checked in this manner. The verification provided by the alarm log and display is not considered in the selection of test and calibration frequencies and is not required for plant safety.

Response times and the provisions for testing the response times for the RPS are provided in the Technical Specifications and in table 7.2-2.

All RPS scram functions are designed to comply with the testability requirements of IEEE 279-1971, Paragraphs 4.9, 4.10, and 4.11, on a periodic basis.

Calibration and test controls for the NMS and trip units are located in the MCR. Their physical location places them under direct physical control of the MCR operator. Calibration and test controls for pressure switches, pressure transmitters, float switches, level transmitters, and valve position switches are located in the turbine and reactor buildings, and the drywell. To gain access to the setting controls on each switch, a cover plate or sealing device must be removed. The MCR operator is responsible for granting access to the setting controls. Only properly

qualified plant personnel are granted access for the purpose of testing or adjusting the calibration.

7.2.2.9 Environmental Considerations

Electrical modules for the RPS are located in the primary containment in the reactor and turbine buildings. The environmental conditions for these areas are discussed in section 3.11.

Cabling for the RPS is run in rigid steel conduit. Separation is in accordance with paragraph 8.3.1.4.1.

Power relays for interrupting the scram pilot valve solenoids are type CR3O5 magnetic contactors made by the General Electric Company (GE). All RPS relays are selected so that the continuous load does not exceed 50% of the continuous duty rating.

Sensing elements have enclosures to withstand conditions resulting from a steam or water line break long enough to perform satisfactorily.

7.2.2.10 Operational Considerations

7.2.2.10.1 Normal

During normal operation, all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized. In contrast, however, trip contact bypass channels consist of normally open contact networks.

7.2.2.10.2 Scram

The following paragraphs discuss the functional considerations for the variables or conditions monitored by the RPS. Table 7.2-1 lists the preliminary specifications for instruments that provide signals for the system. Drawing nos. H-27612 and H-27613 summarize the locations from which the RPS may receive a signal that causes a scram.

There are two pilot scram valves and two scram valves for each control rod, arranged as shown on drawing no. H-24728. Each pilot scram valve is solenoid-operated, with the solenoids normally energized. The pilot scram valves control the air supply to the scram valves for each control rod. When either pilot scram valve is energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for CRD water. As shown on drawing no. H-24728, one of the scram pilot valves for each control rod is controlled by actuator logics A, and the other valve is controlled by actuator logics B. There are two dc solenoid-operated backup scram valves that provide a second means of controlling the air supply to the scram valves for all control rods. The dc solenoid for each backup scram valve is normally deenergized. The backup scram valves are energized (initiating scram) when trip systems A and B are both tripped.

The functional arrangement of sensors and channels that constitute a single logic is shown on drawing no. H-24729. When a channel sensor contact opens, its sensor relay deenergizes, causing contacts in the logic to open. The opening of contacts in the logic deenergizes its actuators. When deenergized, the actuators open contacts in all of the actuator logics for that trip system. This action results in deenergizing the scram pilot valve solenoids associated with that trip system (one scram pilot valve solenoid for each control rod). However, the other scram pilot valve solenoid for each rod must also be deenergized before the rods can be scrammed.

If a trip also occurs in any of the logics of the other trip system, the remaining scram pilot valve solenoid for each rod is deenergized. This permits the air to vent from the scram valves and allows CRD water to act on the CRD piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is vented into the scram discharge header. When the solenoid for each backup scram valve is energized, the backup scram valves vent the air supply for the scram valve. This action initiates insertion of any errant control rods regardless of the action of the scram pilot valves (drawing no. H-24728).

A scram can be initiated manually. There are four scram buttons. Two buttons, one from logic A and one from logic B, must be depressed to initiate a manual scram. The manual scram buttons are close enough to permit one hand motion to cause a scram. By operating the manual scram button for one manual logic at a time, then resetting that logic, each trip system can be tested for manual scram capability. The MCR operator can also scram the reactor by operating power supply breakers to interrupt power to the RPS or by placing the mode switch in its SHUTDOWN position.

To restore the RPS to normal operation following any single trip-system trip or scram, the actuators must be reset manually. The actuators can be reset only after a 10-s delay, but only if the conditions that caused the scram have been cleared. The actuators are reset by operating switches in the control room. Drawing no. H-24729 shows the functional arrangement of reset contacts for trip system A.

When a RPS sensor trips, it lights a printed red annunciator window, common to all the channels for that variable, which indicates the out-of-limit variable. This window is located on the reactor control panel in the MCR. Each trip system lights a red annunciator window which indicates which trip system has tripped. A RPS channel trip also sounds a buzzer or horn which can be silenced by the operator. The annunciator window lights latch in until reset manually. Reset is not possible until the condition causing the trip has been cleared. A computer alarm log and display identifies each tripped channel; however, the physical position of the RPS relays may also be used to identify the individual sensor that tripped in a group of sensors monitoring the same variable. The location of alarm windows permits the operator to quickly identify the cause of RPS trips and to evaluate the threat to the fuel or nuclear system process barrier.

RPS inputs to annunciators, recorders, and the computer are arranged so that no malfunction of the annunciating, recording, or computing equipment can functionally disable the RPS. Direct signals from RPS sensors are not used as inputs to annunciating or data-logging equipment. Relay contact isolation is provided between the primary signal and the information output.

7.2.2.10.3 Operation Information

Indicators

Indicators are installed in the manual scram switches to indicate a trip system manual trip. Scram group indicators extinguish when an actuator logic opens. Process indicators for all RPS trip variables are available in the MCR.

Annunciators

Each RPS input is provided to the annunciator system through isolated relay contacts. Manual and automatic trip system trips also signal the annunciator system.

7.2.2.10.4 Setpoints

To gain access to those calibration and trip-setting controls located outside the MCR, operations personnel must remove a cover plate, access plug, or sealing device before any trip setting can be adjusted.

Trip system setpoints are summarized in table 7.2-1 and discussed below:

A. NMS Trip

To protect the fuel against high-heat generation rates, neutron flux is monitored and used to initiate a reactor scram. The NMS setpoints and their bases are discussed in subsection 7.6.2.

B. Nuclear System High Pressure

High pressure within the nuclear system threatens to rupture the nuclear system process barrier. A nuclear system pressure increase during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes increased core heat generation that could lead to fuel failure and system overpressurization. A scram counteracts a pressure increase by quickly reducing core fission heat generation. The nuclear system high-pressure scram setting is chosen slightly above the RPV maximum normal operating pressure to permit normal operation without spurious scram, yet provides a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transient, was also considered in the selection of the high-pressure scram setting. The nuclear system high-pressure scram setting also protects the core from exceeding thermal-hydraulic limits due to pressure increases during events that occur when the reactor is operating below rated power and flow.

C. RPV Low Water Level (Level 3)

Low water level in the RPV indicates that the fuel is in danger of being inadequately cooled. Decreasing the water level while the reactor is operating at power decreases the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. Should water level decrease too far, fuel damage could result as steam forms around the fuel rods. A reactor scram protects the fuel by reducing the fission heat generation within the core. The RPV water level 3 scram setting was selected to prevent fuel damage following AOOs. These transients are caused by either single equipment malfunctions or single operator errors, and result in a decreasing RPV water level. The scram setting is far enough below normal operational levels to avoid spurious scrams. The setting is high enough above the top of the active fuel to ensure that enough water is available to account for evaporation loss and displacement of coolant following the most severe AOOs involving a level decrease. The selected scram setting was used in developing thermal-hydraulic limits. The limits set operational limits on the thermal power level for various coolant flowrates.

D. Turbine Stop Valve Closure

Closure of the turbine stop valve with the reactor at power can result in a significant addition of positive reactivity to the core as the nuclear system pressure rise causes steam voids to collapse. The turbine stop valve closure scram initiates a scram earlier than does either the NMS or nuclear system high pressure. It is required to provide a satisfactory margin below core thermal-hydraulic limits for this category of AOOs. The scram counteracts the addition of positive reactivity resulting from increasing pressure by inserting negative reactivity with control rods. Although the nuclear system high-pressure scram in conjunction with the pressure relief system is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the nuclear system pressure limit. The turbine stop valve closure scram setting provides the earliest positive indication of valve closure.

E. Turbine Control Valve Fast Closure

With the reactor and turbine-generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The turbine control valve fast closure scram initiates a scram earlier than either the NMS or nuclear system high pressure. It is required to provide a satisfactory margin to core thermal-hydraulic limits for this category of AOOs. The scram counteracts the addition of positive reactivity resulting from increasing pressure by inserting negative reactivity with control rods. Although the nuclear system high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine control valve fast closure scram provides additional margin to the nuclear system pressure limit. The turbine control valve fast closure scram setting is selected to provide timely indication of turbine control valve fast closure.

F. Main Steam Line Isolation

The MSIV closure scram limits the release of fission products from the nuclear system. Automatic closure of the MSIVs is initiated when conditions indicate a steam line break. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The logic allows functional testing of main steam line trip channels with one steam line isolated.

G. Scram Discharge Volume High Water Level

Water displaced by the CRD pistons during a scram goes to the scram discharge volume. If the scram discharge volume fills with the water so that insufficient capacity remains for the water displaced during a scram, control rod movement would be hindered during a scram. To prevent this situation, the reactor is scrammed when the water level in the discharge volume is high enough to verify that the volume is filling up, yet low enough to ensure that the remaining capacity in the volume can accommodate a scram.

H. Primary Containment High Pressure

High pressure inside the primary containment may indicate a break in the nuclear system process barrier. It is prudent to scram the reactor in such a situation in order to minimize the possibility of fuel damage and to reduce energy transfer from the core to the coolant. The drywell high-pressure scram setting is selected to be as low as possible without inducing spurious scrams.

I. Main Steam Line High Radiation

High radiation in the vicinity of the main steam lines may indicate a gross fuel failure in the core. When high radiation is detected near the steam lines, a high-radiation signal is generated activating appropriate alarms and isolations, but there is no initiation of a scram or primary containment/RPV isolation resulting from this signal. More information on the trip setting is available in subsection 7.6.3.

J. Manual Scram

Pushbuttons are located in the MCR to enable the operator to shut down the reactor by initiating a scram.

K. Mode Switch in SHUTDOWN

When the mode switch is in SHUTDOWN, the reactor is to be shut down with all control rods inserted. This scram is not considered a protective function because it is not required to protect the fuel or nuclear system process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short delay, permitting a scram reset that restores the normal valve lineup in the CRD hydraulic system.

7.2.2.10.5 Mode Switch

A conveniently located, multiposition, keylock mode switch is provided to select the necessary scram functions for various plant conditions. The mode switch selects the appropriate sensors for scram functions and provides appropriate bypasses. The switch also interlocks such functions as control rod blocks and refueling equipment restrictions which are not considered here as part of the RPS. The switch is designed to provide separation between the two trip systems. The mode switch positions and their related scram functions are shown in figure 7.2-1; they are:

A. SHUTDOWN

Initiates a reactor scram; bypasses main steam line isolation scram.

B. REFUEL

Selects neutron monitoring system scram for low neutron flux level operation; bypasses main steam line isolation scram.

C. STARTUP

Selects NMS scram for low neutron flux level operation; bypasses main steam line isolation scram.

D. RUN

Selects NMS scram for power range operation.

7.2.3 ANALYSIS

7.2.3.1 General

Presented below are analyses to demonstrate how the various general functional requirements and the specific regulatory requirements listed under the RPS design bases described in subsection 7.2.1 are satisfied. Considerations of loss of instrument air and loss of cooling water to vital equipment are discussed in chapter 15.

7.2.3.2 Conformance With Functional Requirements

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier and nuclear system process barrier. The methods of assessing barrier damage and radioactive material releases are presented in chapter 15.

Design procedures select tentative scram trip setting such that spurious scrams and operating inconvenience are avoided. It is then verified by analysis that the reactor fuel and nuclear system process barriers are protected. In all cases, the specific scram trip point selected is a value that prevents damage to the fuel or nuclear system process barriers, taking into consideration previous operating experience.

The scrams initiated by NMS variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and RPV low water level prevent fuel damage following AOOs. Specifically, these scram functions initiate a scram in time to prevent the core from exceeding the thermal-hydraulic safety limit during AOOs identifies and evaluates the threats to fuel integrity posed by AOOs. In no case does the core exceed the thermal-hydraulic safety limit.

The scram initiated by nuclear system high pressure, in conjunction with the pressure relief system, is sufficient to prevent damage to the nuclear system process barrier as a result of internal pressure. For turbine-generator trips, the stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the nuclear system pressure safety limit than does the high-pressure scram. The turbine stop valve and turbine control valve fast closure events are described in chapter 15. The relays, sensors, and wiring for that portion of the RPS which deals with generator load rejection and turbine trip meet all of the qualifications of Class 1E equipment (IEEE-279, etc.), the same standards as other inputs to the RPS, and meet all of the criteria for the RPS contained in 10 CFR 50 (1976), Appendix A, with the only exception being that they are housed in a building that is not seismically qualified. The sensors meet IEEE-279 separation requirements, including qualified isolation for each circuit; they are deenergized to function; i.e., fail in the safe or scram direction. If the circuits were somehow severed, the result would be a loss of power and a reactor scram. In the unlikely event of a turbine building failure that affects these signals, it would be most likely that a reactor scram would result. The RPT system is also initiated by these same sensors for the two events in question and the same degree of qualification applies. The RPT system itself is also qualified as Class 1E. It should also be emphasized that all the equipment which is the subject of this concern is identical to that previously licensed on all boiling water reactor (BWR) plants to date.

With regard to reliance being placed on the turbine control valve fast closure and turbine stop valve closure scram functions (with RPT), it should be noted that such reliance is not required for a seismic event. Credit is taken for these functions only when the evaluation is made against the stringent requirements of 10 CFR 20.1 - 20.601 (found in 10 CFR published before January 1994), in the context of mitigating an AOO so that fuel-cladding integrity is preserved. Evaluation of a generator loss of load or turbine trip coincident with the seismic (design basis earthquake) event would be made against the requirements of 10 CFR 100 because of the much lower probability of the event. For this situation, and in the unlikely event that either of the direct scram functions should be impaired, the neutron flux trip would serve as a backup and would limit radiological releases, if any, to well below the 10 CFR 100 requirements. Chapter 15 identifies and evaluates accidents and AOOs that result in nuclear system pressure increases. In no case does pressure exceed the nuclear system safety limit.

The scrams initiated by MSIV closure and RPV low water level satisfactorily limit the radiological consequences of gross failure of the fuel or nuclear system process barriers. Chapter 15 evaluates gross failures of the fuel and nuclear system process barriers. In no case does the

release of radioactive material to the environs result in exposures which exceed the guideline values of applicable published regulations.

Neutron flux is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in subsection 7.6.2. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities.

The RPS uses one-out-of-two-taken-twice logic. Theoretically, its reliability is slightly higher than a two-out-of-three system and slightly lower than a one-out-of-two system. The dual trip system is advantageous because it can be thoroughly tested during reactor operation without causing a scram. This capability for a thorough testing program significantly increases reliability.

The use of an independent channel for each logic input allows the system to sustain any channel failure without preventing other sensors which monitor the same variable from initiating a scram. Any maintenance operation, calibration operation, or test results in only a single trip-system trip. This leaves at least two channels per monitored variable capable of initiating a scram. The resistance to spurious scrams contributes to plant safety because reduced cycling of the reactor through its operating modes decreases the probability of error or failure.

When an essential monitored variable exceeds its scram trip point, it is sensed by at least two independent sensors in each trip system. Only one channel must trip in each trip system to initiate a scram. Thus, the arrangement of two channels per trip system ensures that a scram occurs as a monitored variable exceeds its scram setting.

Each control rod is controlled as an individual unit. A failure of the controls for one rod would not affect other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required.

Sensors, channels, and logics of the RPS are not used for control of process systems. Therefore, failure in the instrumentation and control of process systems cannot induce failure of any portion of the protection system.

Failure of either RPS motor-generator set would result, at worst, in a single trip-system trip. Alternate power is available to the RPS buses. A complete, sustained loss of electrical power to both buses would result in a scram, delayed by the motor-generator set flywheel inertia.

Alarm trip settings for each local power range monitor (LPRM) channel are revised as necessary by the process computer. These setpoints are based on computer calculations of the core power distributions and appropriate reactor operating limit criteria. Upon alarm trip setting revisions by the process computer, an alarm is sounded to alert the operator to the necessary adjustment.

During normal operating conditions, LPRM readings are made once per minute. During power level changes, the scanning frequency is increased to once every 5 s. The process computer system is described in subsection 7.6.8.

The environment in which the instruments and equipment of the RPS must operate was considered in setting the environmental specification discussed in section 3.11. The specifications for the instruments located in the reactor or turbine buildings are based on the worst expected ambient conditions.

The control room maximum environment is predicated on supplying the MCR with 100% outside air with no refrigeration. The minimum environment is predicated on a mixture of outside and recirculated air concurrent with a minimum equipment heat loss. The condensing chambers are the RPS components that must function in the environment resulting from a nuclear system process barrier break inside the primary containment. Special precautions are taken to ensure operability after the accident. The condensing chambers and all essential components of the control and electrical equipment are either similar to those that have successfully undergone qualification testing in connection with other projects or additional qualification testing under simulated environmental conditions was conducted.

Design of the system to comply with safety class requirements and the fail-safe characteristics of the system ensure safe shutdown of the reactor during earthquake ground motion. The system only fails in a direction that causes a reactor scram when subjected to extremes of vibration and shock.

To ensure that the RPS remains functional, the number of operable channels for the essential monitored variables is maintained at or above the minimum given in tables 7.2-3 and 7.2-4. The minimum applies to any untripped trip system; a tripped trip system may have any number of inoperative channels. Because reactor protection requirements vary with the mode in which the reactor operates, the tables show different functional requirements for the RUN and STARTUP modes. These are the only modes in which more than one control rod can be withdrawn from the fully inserted position.

In case of a LOCA, reactor shutdown occurs immediately following the accident as one or more process variables exceed their specified setpoint. Operation verification that shutdown has occurred may be made by observing one or more of the following indications:

- Control rod status lamps indicating each rod fully inserted.
- Control rod scram pilot valve status lamps indicating open valves.
- Neutron monitoring power range channels and recorders downscale.
- Annunciators for RPS variables and trip logic in the tripped state.
- Process computer logging of trips and control rod position log.

7.2.3.3 Conformance to Specific Regulatory Requirements

IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," is satisfied as follows:

NEDO-10139, "Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam Supply System," demonstrates compliance of the RPS with IEEE 279-1968.

The following is a description of those areas of IEEE 279-1971 that are different from IEEE 279-1968:

- Paragraph 4.7, Control and Protection System Interaction.

  - Paragraph 4.7.1, Classification of Equipment.

    The system has no control function; it is strictly a protection system.

  - Paragraph 4.7.2, Isolation Devices.

    Since there is no control function, no isolation devices are required.

  - Paragraph 4.7.3, Single Random Failure.

    No single random failure of a control system can prevent proper action of the RPS channel designed to protect against the condition.

  - Paragraph 4.7.4.

    The analysis of paragraph 4.7.3 applies directly.

- Paragraph 4.I7, Manual Initiation.

  No single failure in the manual or automatic portions of the RPS can prevent either manual or automatic scram.

- Paragraph 4.22, Identification of Protection Systems.

  Each system cabinet is marked with the words "Reactor Protection System" and the particular redundant portion is listed on a distinctively colored marker plate. Cabling outside the cabinets is identified by color coding (as discussed in paragraph 8.3.I.4).

Exact design comparisons with the testability requirements of IEEE 279-1971, 4.9, 4.10, and 4.11 are given in topical report NEDO-10139:

	Page
• Scram discharge volume	2-26, 2-27
• MSIV	2-39
• Turbine stop valve	2-56, 2-57
• Turbine control valve	2-69, 2-70
• RPV level	2-99
• NMS	2-125
• Drywell pressuree	2-138
• RPV pressure	2-146
• Manual scram	2-158
• Mode switch	2-164, 2-165
• Discharge volume bypass	2-170, 2-171
• Main steam line valve bypass	2-178
• Turbine trip bypass	2-186

The RPS is fail-safe and its power supplies are thus unnecessary for scram. A total loss of power causes a scram. A loss of one power source causes a trip system trip. IEEE 308-1971, "Criteria for Class 1E Electric Systems," does not apply to the RPS.

IEEE 323-1971, "General Guide for Qualifying Class 1 Electric Equipment," is satisfied by complete qualification testing and certification of all essential components. Records covering all essential components are maintained. Compliance with the requirements of IEEE 323-1971 is discussed in section 3.11. Equipment required to operate in harsh environments is qualified to Rulemaking 10 CFR 50.49. Records covering this equipment are maintained in the Plant Hatch Central File.

IEEE 336-1971, "Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During Construction of Nuclear Power Generating Stations," is satisfied.

IEEE 338-1971, "Periodic Testing of Protection Systems," is complied with by being able to test the RPS from sensors to final actuators at any time during plant operation. The test must be performed in overlapping portions.

IEEE 344-1971, "Trial Use Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations," is satisfied by all Class 1 RPS equipment as described in section 3.10.

Regulatory Guide 1.22. The RPS is designed so that it may be tested during plant operation from sensor device to final actuator device in compliance with Regulatory Guide 1.22 (February 1972). The test must be performed in overlapping portions so that an actual reactor scram does not occur as a result of the testing.

10 CFR 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants. A quality assurance program was established that includes quality control at the component vendor, at the nuclear steam supplier, at various stages of construction, and during installation at the nuclear power plant site. System design is continually checked for conformance to the applicable industry criteria. Periodic testing ensures that the system is available and adequate to perform its intended purpose. Quality assurance records are maintained by the nuclear steam supplier and at the nuclear power plant site. For a complete description of the quality assurance program, see chapter 17.

General Design Criteria (GDC) of 10 CFR 50, Appendix A

A. GDC 13 -- Each RPS input is monitored and annunciated.

B. GDC 19 -- Instrumentation and control is provided in the MCR. The reactor can also be shut down from outside the MCR by opening breakers.

C. GDC 20 -- The RPS constantly monitors the appropriate plant variables to maintain the fuel barrier and primary coolant pressure boundary. It automatically initiates a scram when the variables exceed the established setpoints.

D. GDC 21 -- The RPS is designed with four independent and separated input channels and four independent and separated output channels. No single failure or operator action can be tested during plant operation to ensure its availability.

E. GDC 22 -- The redundant portions of the RPS are separated such that no single failure or credible natural disaster can prevent a scram. Functional diversity is employed by measuring flux, pressure, and level (all dependent variables) in the reactor vessel.

F. GDC 23 -- The RPS is fail-safe. A loss of electrical power or air supply does not prevent a scram. Postulated adverse environments do not prevent a scram.

G. GDC 24 -- The RPS has no control function.

H. GDC 29 -- The RPS is highly reliable so that it scrams in the event of AOOs.

TABLE 7.2-1

RPS INSTRUMENTATION SPECIFICATIONS

Scram/Function	Instrument	Trip Setting
Nuclear system pressure - high	Pressure transmitter/trip unit	(a)
Primary containment pressure - high	Pressure transmitter/trip unit	(a)
RPV water level - low (level 3)[b]	Differential pressure transmitter/trip unit	(a)
Scram discharge volume water level level - high	Level switch	(a)
	Resistance temperature detector	(a)
Turbine stop valve closure	Position switch	(a)
Turbine control valve fast closure	Pressure switch	(a)
MSIV closure	Position switch	(a)
NMS scram	(See subsection 7.6.2)	

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero; see figure 5.4-2.

TABLE 7.2-2

RESPONSE TIMES ASSUMED FOR SAFETY ANALYSIS

Function	Response Time (s)
APRM neutron flux high	(a)
MSIV closure	(a)
Turbine stop valve closure	(a)
Turbine control valve fast closure	(a)

a. RPS response times are specified in the HNP-2 Technical Requirements Manual.

TABLE 7.2-3

CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE OF RPS (STARTUP MODE)

This table shows the normal and minimum number of channels required for the functional performance of the RPS in the startup mode. The "Normal" column lists the normal number of channels per trip system. The "Minimum" column lists the minimum number of channels per untripped trip system required to maintain functional performance.

Channel Description	Normal	Minimum[a]
NMS (APRM)	4	3
NMS (two-out-of four voter)	2	2
NMS (IRM)	4	3
Nuclear system high pressure	2	2
Primary containment high pressure	2	2
RPV water level 3	2	2
Scram discharge volume high water level		
- Float switches	2	2
- Thermal level switches	2	2
Manual scram	1	1

a. During testing of sensors, the channel should be tripped when the initial state of the sensor is not essential to the test.

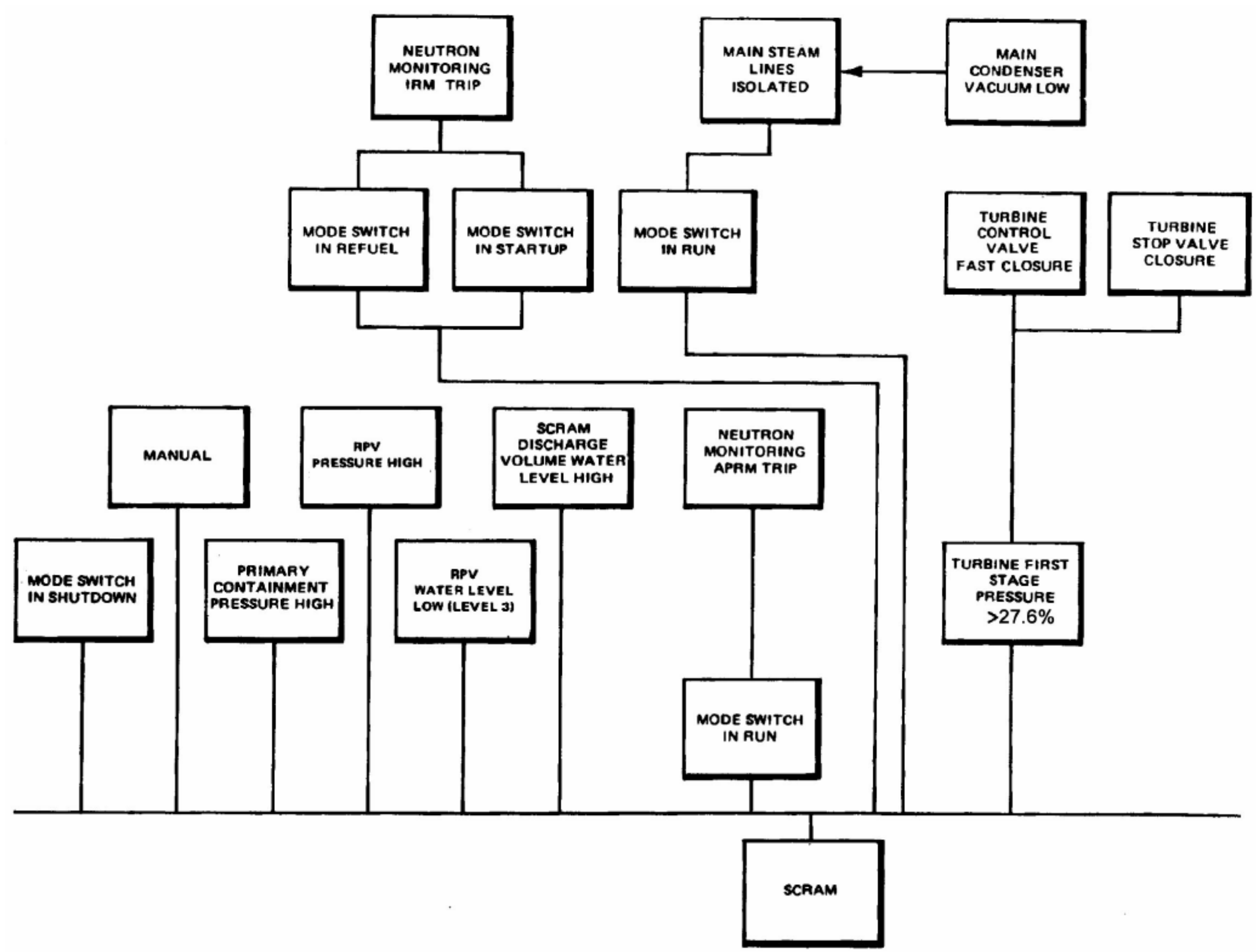
TABLE 7.2-4

CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE OF RPS (RUN MODE)

This table shows the normal and minimum number of channels required for the functional performance of the RPS in the RUN mode. The "Normal" column lists the normal number of channels per trip system. The "Minimum" column lists the minimum number of channels per untripped trip system required to maintain functional performance.

Channel Description	Normal	Minimum[a]
NMS (APRM)	4	3
NMS (two-out-of-four voter)	2	2
Nuclear system high pressure	2	2
Primary containment high pressure	2	2
RPV water level 3	2	2
Scram discharge volume high water level		
- Float switches	2	2
- Thermal level switches	2	2
Manual scram	1	1
Each MSIV position	2/valve	2/valve
Each turbine stop valve position	2/valve	2/valve
Turbine control valve fast closure	2	2
Turbine first stage pressure (bypass channel)	2	2

a. During testing of sensors, the channel should be tripped when the initial state of the sensor is not essential to the test.



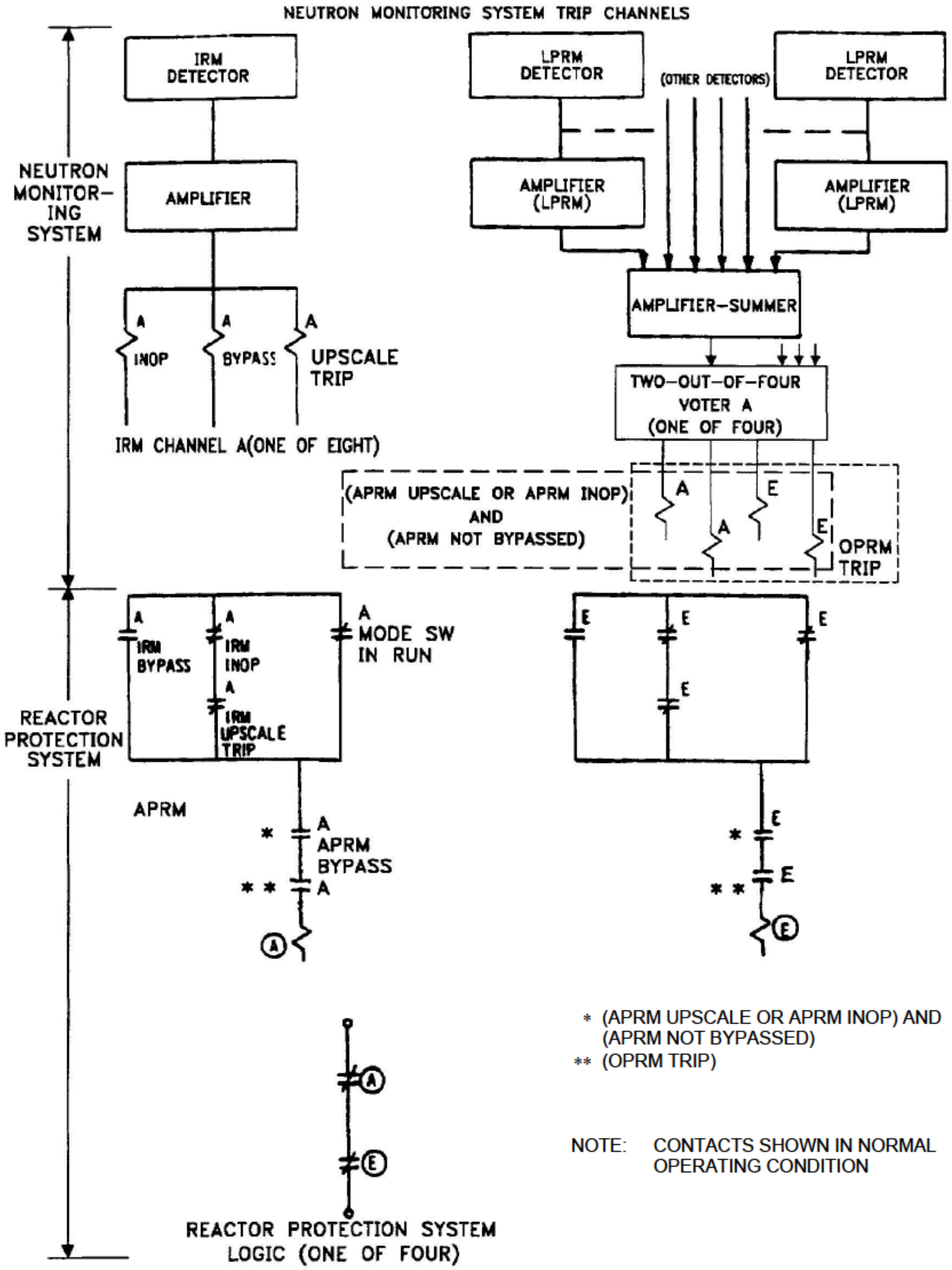
REV 22 9/04

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

RPS SCRAM FUNCTIONS

FIGURE 7.2-1



ACAD 2070202

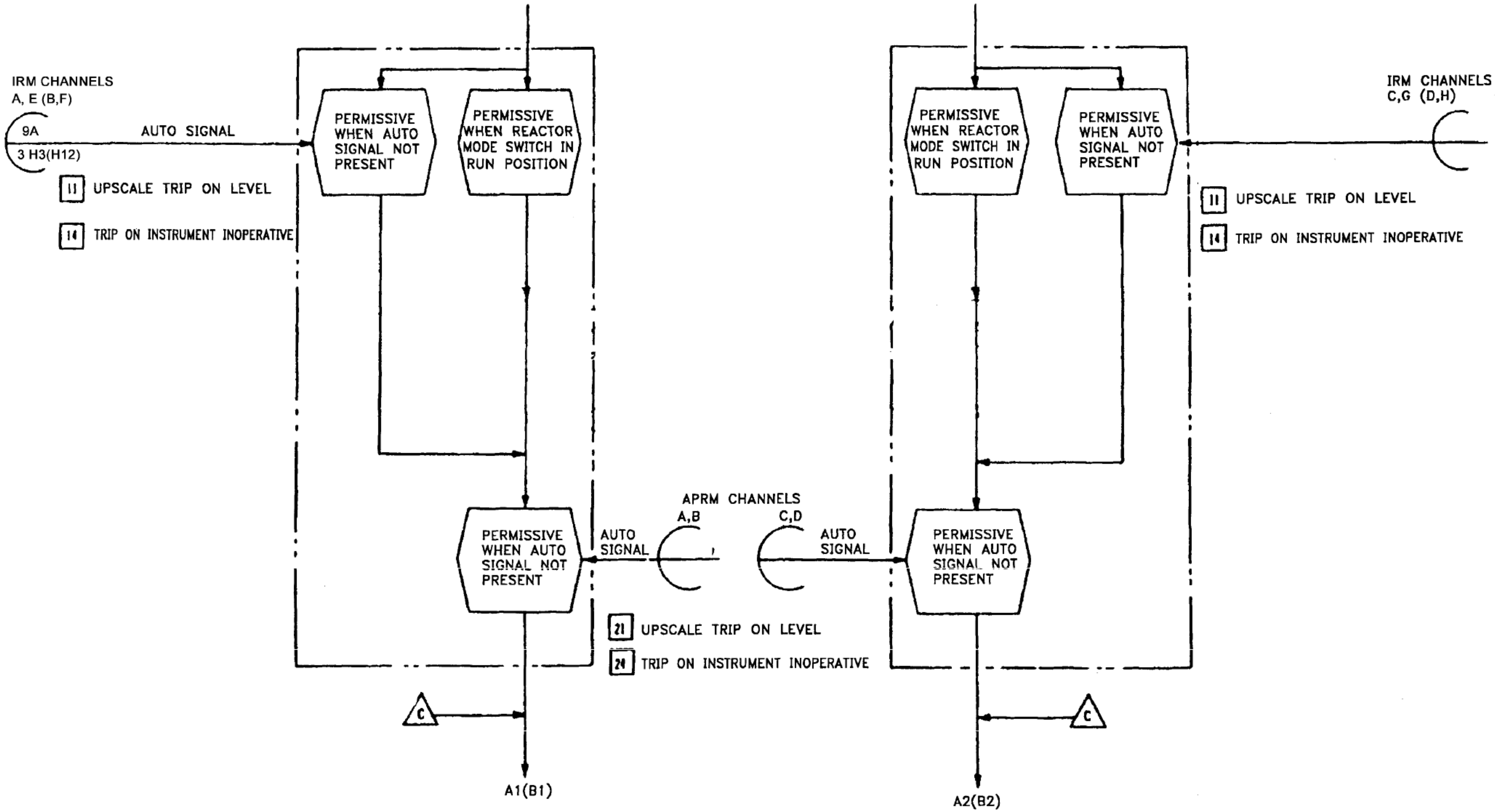
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RPS RELATIONSHIP TO NMS

FIGURE 7.2-2



ONE OF TWO NEUTRON MONITORING SYSTEM LOGICS ASSOCIATED WITH REACTOR PROTECTION SYSTEM LOGIC A1

ONE OF TWO NEUTRON MONITORING SYSTEM LOGICS ASSOCIATED WITH REACTOR PROTECTION SYSTEM LOGIC A2

ACAD 2070203

REV 19 7/01

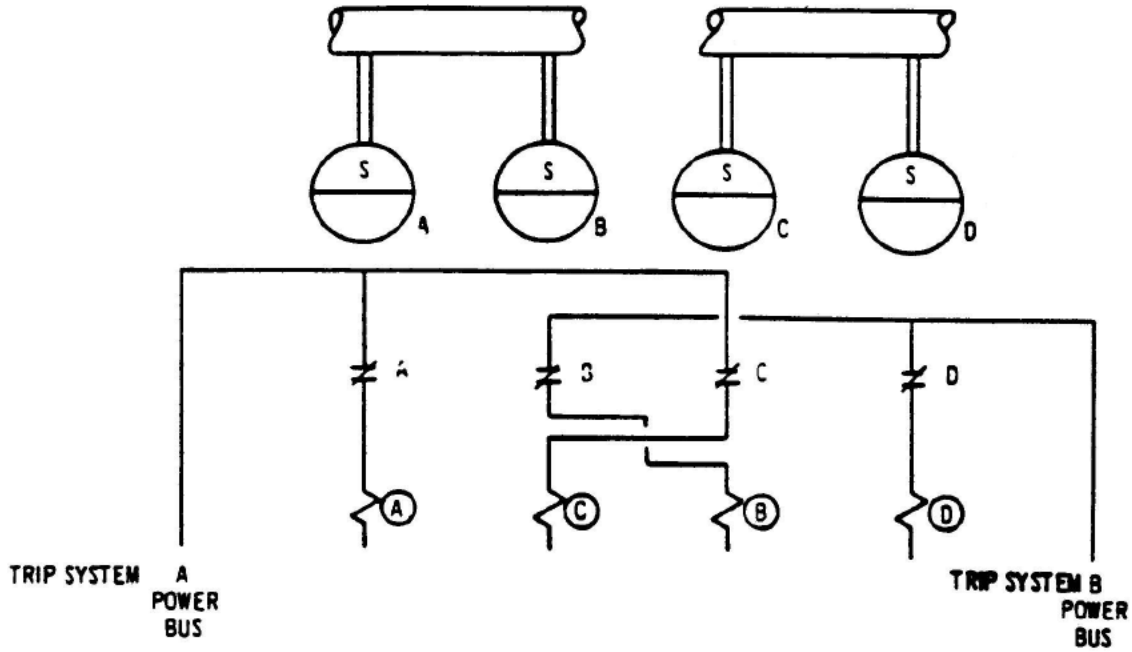
SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

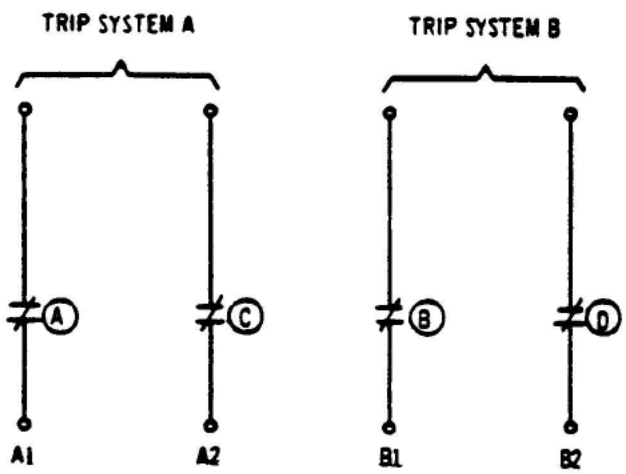
RPS NMS TRIP SYSTEM LOGIC

FIGURE 7.2-3

SENSORS



CHANNELS



NOTE: CONTACTS SHOWN ARE IN NORMAL OPERATING CONDITION

REACTOR PROTECTION SYSTEM LOGICS

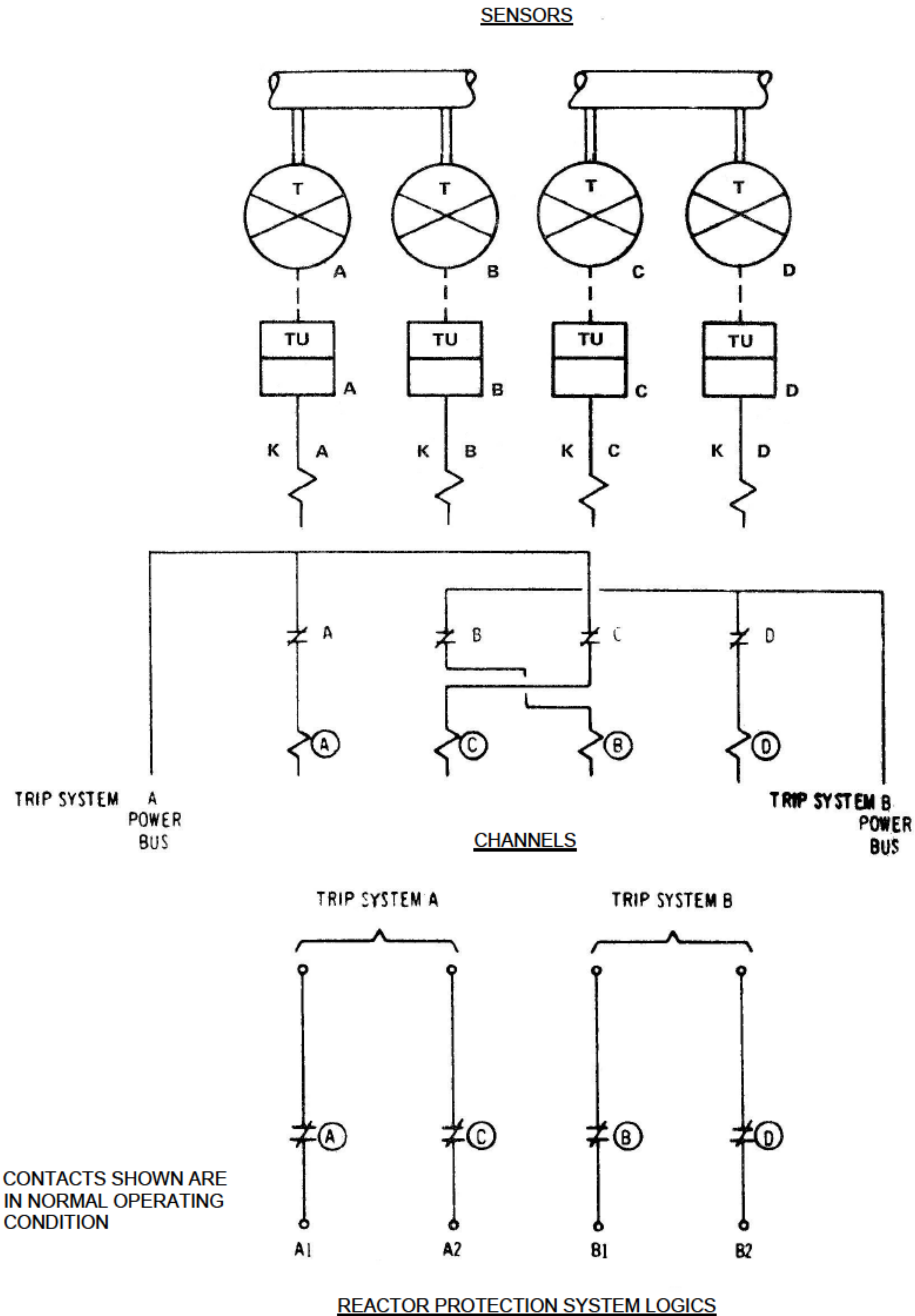
TYPICAL CONFIGURATION FOR:
SCRAM DISCHARGE VOLUME HIGH WATER LEVEL (FLOW SWITCHES)
SCRAM DISCHARGE VOLUME HIGH WATER LEVEL (THERMAL SWITCHES)
TURBINE CONTROL VALVE FAST CLOSURE

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL ARRANGEMENT OF
RPS CHANNELS AND LOGICS

FIGURE 7.2-4 (SHEET 1 OF 2)



NOTE: CONTACTS SHOWN ARE IN NORMAL OPERATING CONDITION

TYPICAL CONFIGURATION FOR
REACTOR VESSEL LOW WATER LEVEL
PRIMARY CONTAINMENT HIGH PRESSURE
NUCLEAR SYSTEM HIGH PRESSURE

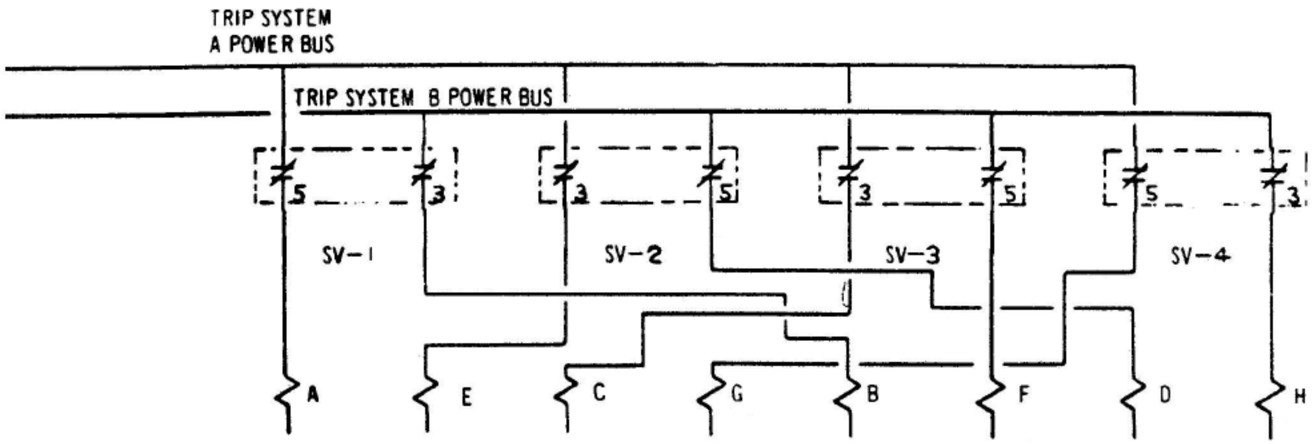
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

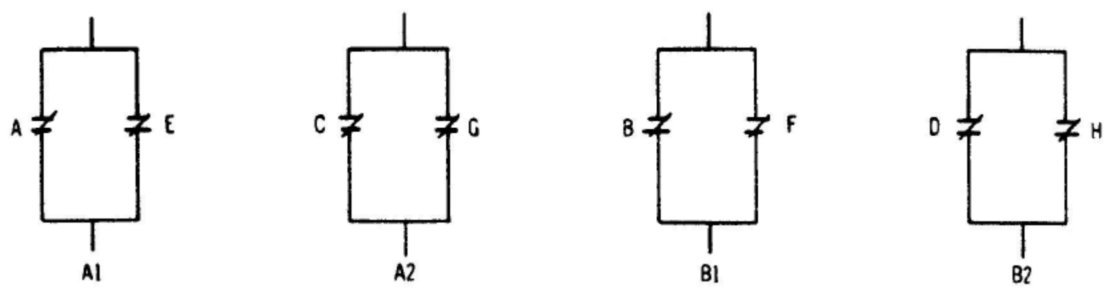
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL ARRANGEMENT OF RPS CHANNELS AND LOGICS

FIGURE 7.2-4 (SHEET 2 OF 2)



TURBINE STOP VALVE CLOSURE CHANNELS



REACTOR PROTECTION SYSTEM LOGICS

NOTE: CONTACTS SHOWN ARE IN NORMAL OPERATING CONDITION

SV = STOP VALVE

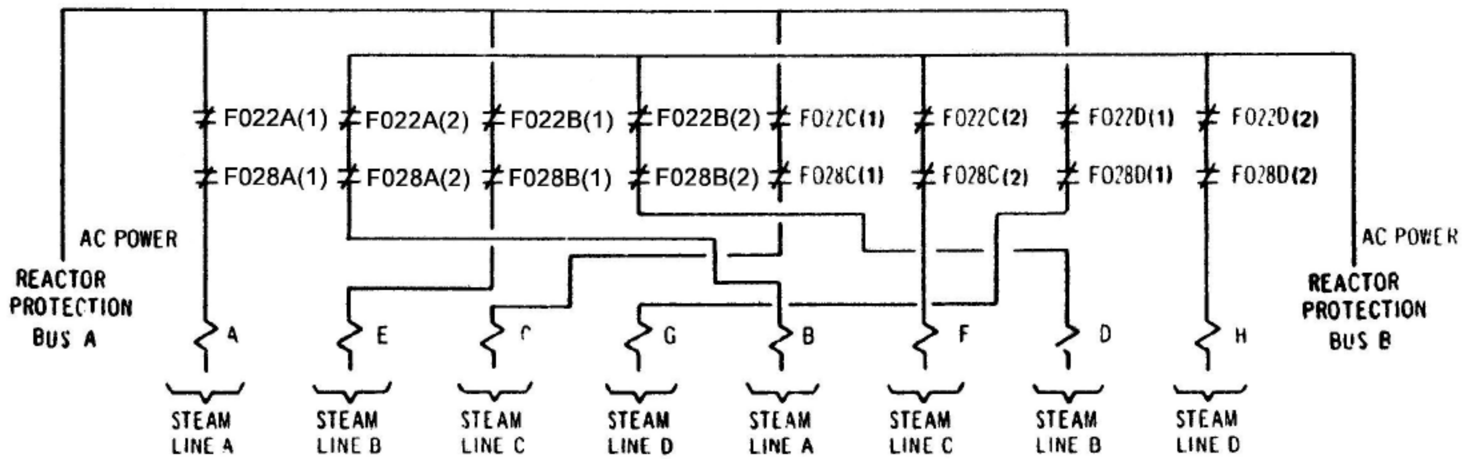
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

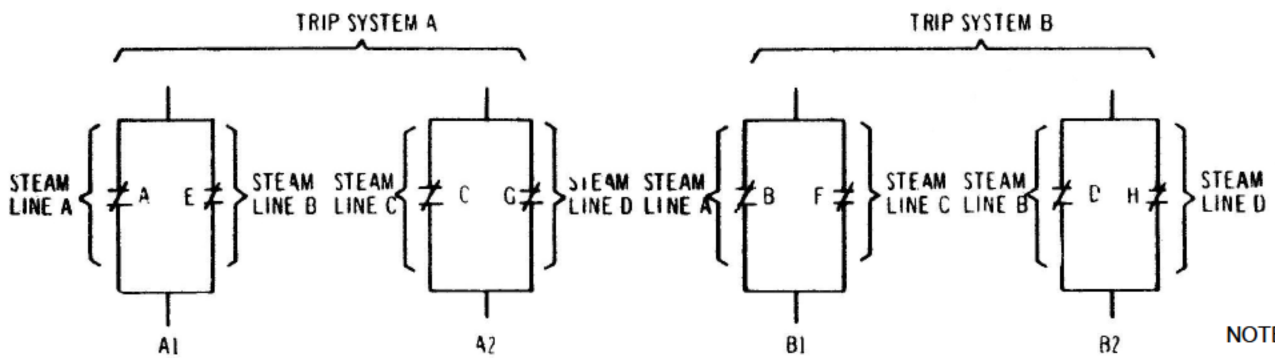
RPS TURBINE STOP VALVE CLOSURE
SCRAM CONFIGURATION

FIGURE 7.2-5



MAIN STEAM LINE ISOLATION CHANNELS

(SWITCH CONTACTS SHOWN IN POSITIONS WHEN ISOLATION VALVES < 10% CLOSED)



NOTE: CONTACTS SHOWN IN NORMAL OPERATING CONDITIONS

REACTOR PROTECTION SYSTEM LOGICS

KEY:
F022A - STEAM LINE A, INBOARD VALVE
F028A - STEAM LINE A, OUTBOARD VALVE
F022B - STEAM LINE B, INBOARD VALVE
F028B - STEAM LINE B, OUTBOARD VALVE
F022C - STEAM LINE C, INBOARD VALVE
F028C - STEAM LINE C, OUTBOARD VALVE
F022D - STEAM LINE D, INBOARD VALVE
F028D - STEAM LINE D, OUTBOARD VALVE

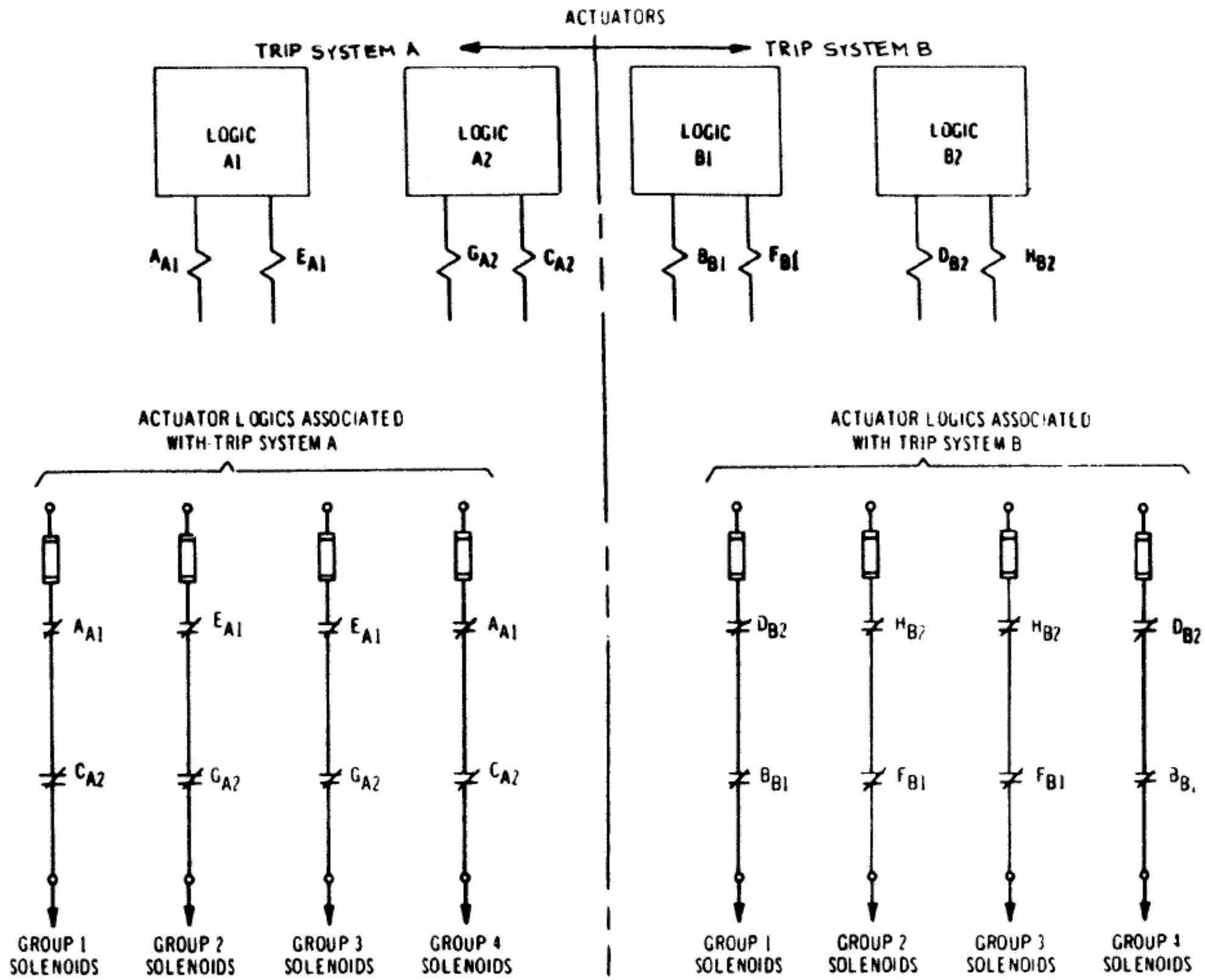
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RPS MAIN STEAM LINE ISOLATION SCRAM CONFIGURATION

FIGURE 7.2-6



NOTE: CONTACTS SHOWN IN NORMAL OPERATING CONDITION

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ARRANGEMENT OF RPS ACTUATORS AND ACTUATOR LOGICS

FIGURE 7.2-7

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

The instrumentation and controls of the following engineered safety feature (ESF) systems are discussed in this section:

- Emergency core cooling system (ECCS).
- Primary containment and reactor pressure vessel (RPV) isolation system.
- Standby gas treatment system (SGTS).
- Main control room environmental control (MCREC) system.

The standby power system and the essential power distribution systems are discussed in chapter 8.

There is no instance wherein the single failure, either in the fail-to-function sense or the undesirable-function sense, of a manually controlled, electrically operated valve causes the failure of the system to perform its safety function. This includes valves that are required to operate for the safety function and those that are not.

7.3.1 EMERGENCY CORE COOLING SYSTEM

7.3.1.1 Design Bases

The ECCS instrumentation and control is designed to meet the following functional safety design bases:

A. They automatically initiate and control the ECCS to prevent fuel-cladding temperatures from reaching the Nuclear Regulatory Commission (NRC) final acceptance criterion.

B. They respond to a need for emergency core cooling, regardless of the physical location of the malfunction or break.

C. The following safety design bases are specified to limit dependence on operator judgment in times of stress:

   1. The ECCS responds automatically so that no action is required of plant operators within 10 min after a loss-of-coolant accident (LOCA).

   2. The performance of the ECCS is indicated by main control room (MCR) instrumentation.

   3. Facilities for manual control of the ECCS are provided in the MCR.

The ECCS instrumentation and control is designed to meet the following specific regulatory requirements:

A. The instrumentation and control meets the requirements of Institute of Electrical and Electronic Engineers (IEEE) 279-1971. The following safety design bases are specified to ensure reliability:

   1. No single malfunction, maintenance, calibration, or test procedure prevents function of the ECCS.

   2. No protective device automatically interrupts performance or availability of the ECCS unless continued operation would cause complete failure. Such protective devices indicate abnormal conditions for operator decision and action.

B. The instrumentation and control meets the requirements of IEEE 338-1971, IEEE 323-1971, and IEEE 344-1971.

C. The requirements of General Design Criteria (GDC) 13, 20-24, 27, and 29 of 10 CFR 50, Appendix A, are met.

D. The requirements of Regulatory Guide 1.22 are met.

7.3.1.2 System Descriptions

General

The ECCS subsystems are as follows:

- High-pressure coolant injection (HPCI) system.
- Automatic depressurization system (ADS).
- Core spray (CS) system.
- Low-pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system.

The purpose of ECCS instrumentation and control is to initiate appropriate responses from the ECCS to ensure that the fuel is adequately cooled in the event of a design basis LOCA. The cooling provided by the system restricts the release of radioactive material from the fuel by preventing or limiting the extent of fuel damage following situations in which reactor coolant is lost from the nuclear steam supply system (NSSS).

The equipment involved in the control of these systems includes automatic injection valves, steam turbine pump controls, electric pump controls, relief valve controls, the switches,

contacts, and relays that make up sensory logic channels and the analog transmitter trip system (ATTS). Certain automatic isolation valves are not included in this description since they are pertinent to the primary containment and RPV isolation control system (subsection 7.3.2).

Separation within the ECCS is such that no single failure can prevent core cooling. Instrumentation and control equipment and wiring are segregated into separate divisions designated either division I or II. Separate requirements are also maintained for the control and motive power for the ECCS. Electrical separation is as follows:

Division I	Division II
CS pump A	CS pump B
ADS	HPCI
RHR A and D	RHR B and C

Systems shown opposite each other are redundant; however, in the event of loss of division I control power to ADS, ADS will be automatically transferred to division II backup control power. In addition, the ADS backs up the HPCI system. Control logic power for all division I systems is supplied from 125 V-dc, cabinet 2A, and for division II systems the power is supplied from 125 V-dc, cabinet 2B.

The ECCS subsystems are designed to be completely testable. Specific test schedules for these and subsequent systems in this section are given in the Technical Specifications. Systems providing core cooling water are arranged with bypass valves so that pumps may be operated at design flow. Control design is such that the system automatically returns from the test to the operating mode if system initiation is required.

Instrumentation and control are designed to establish that the following functions are met:

A. Each instrument channel functions independently of all others.

B. Sensing devices respond to process variables and provide channel trips at correct values.

C. Sensors and associated instrument channels respond to both steady-state and transient changes in the process variable within specified accuracy and time limitations, and they provide channel trips at correct values even when affected by process variations that may extend grossly beyond the expected trip setpoint.

D. Paralleled circuit elements can perform their intended function independently.

E. Series circuit elements are free from shorts that can abrogate their function.

F. Redundant instruments of logic channels are free from interconnecting shorts that could violate independence if a single malfunction should occur.

G. No element of the system is omitted from the test if it could impair system operability in any way. (If the test is done in parts, then the parts must overlap sufficiently to ensure operability of the entire system.)

H. Each monitoring alarm or indication function is operable.

Power Sources

The instrumentation and control of the ECCS is powered by the essential 125/250 V-dc power system, the 120-208 V-ac instrument power system, and the standby power system when required. The redundancy and separation of these power supply systems are consistent with the redundancy and separation of ECCS instrumentation and control. These power supply systems are described in detail in paragraphs 8.3.2.1.1 and 8.3.1.1.4, respectively.

7.3.1.2.1 HPCI System Instrumentation and Control

When actuated, the HPCI system pumps water from either the condensate storage tank (CST) or the suppression chamber to the RPV via the feedwater pipelines. The HPCI system includes one turbine-driven pump, one dc motor-driven auxiliary oil pump, one gland-seal condenser dc motor-driven condensate pump, one gland-seal condenser dc motor-driven blower, other auxiliaries, automatic valves, control devices for this equipment, sensors, trip channels, and logic circuitry. The HPCI piping and instrumentation diagram is shown on drawing nos. H-26020 and H-26021.

Pressure and level switches and transmitters used in the HPCI system are located on racks in the reactor building. The only operating component for the HPCI system that is located inside the primary containment is one of the two isolation valves in the HPCI turbine steam supply pipeline isolation valves. The rest of the HPCI system instrumentation and control components are located outside the primary containment. Cables connect the sensors to trip units and other control circuitry in the MCR. Although the system is arranged to allow a full-flow functional test of the system during normal reactor power operation, the system is declared inoperable while in the test mode. The test controls are arranged so that the test valve returns automatically to the closed position if an initiation signal occurs during a test.

The controls automatically initiate the HPCI system upon the receipt of either a RPV water level 2 signal or a drywell high-pressure signal and bring the system to its design flowrate within 75 s. The controls then function to provide design makeup water flow to the RPV until the water level in the RPV reaches an upper limit. At this time the HPCI system shuts down until further need is indicated. The controls are arranged to allow manual startup, operation, and shutdown from the MCR.

7.3.1.2.1.1 **Initiating Circuits**. The RPV water level 2 and primary containment drywell high pressure are the two functions which can automatically start the HPCI system, as indicated on drawing nos. H-24742 through H-24749.

RPV Water Level 2

The RPV low water level 2 is monitored by four level transmitters which sense the differences between the pressure due to a constant reference column of water and the pressure due to the actual height of water in the vessel. Cables from these transmitters are routed to the associated level-indicating switches (trip units) located in the MCR. The RPV water level-initiate allowable value which is used for the ECCS, is listed in table 7.3-1. The RPV water level-isolate allowable value, which isolates the HPCI and reactor core isolation cooling (RCIC) turbines, is listed in table 7.3-1. (This level value is RPV water level 8.)

Two pipelines, attached to taps above and below the normal water level of the RPV, are required for each set of the level transmitters. The pipelines are physically separated from each other and tap off the RPV at widely separated points. These same lines are also used for pressure and water level instruments for other systems. The level transmitters and primary containment pressure transmitters for the HPCI are arranged in pairs, with the output relay contacts of the subject transmitter's trip units in a one-out-of-two-taken-twice electrical arrangement. This arrangement ensures that no single event can prevent HPCI initiation from RPV water level 2 or drywell high pressure. Cables from the level and pressure transmitters lead to the MCR for logic and sequencing action.

Drywell High Pressure

The primary containment high-pressure initiation signal for the HPCI system uses relay contacts from the CS system, as described in paragraph 7.3.1.2.3. The RPV level and primary containment pressure instrumentation mentioned above is part of the ATTS, which is discussed in section 7.8.

7.3.1.2.1.2 **Logic and Sequencing**. The logic scheme used for the initiating functions is a one-out-of-two-taken-twice arrangement for the combination of RPV water level 2 and high drywell pressure. Either one can initiate HPCI. The logic is powered from essential 125/250-V dc buses.

Instrument settings for the HPCI system instrumentation and control are listed in table 7.3-1. The RPV water level 2 setting for HPCI initiation is selected high enough above the active fuel to start HPCI in time to prevent fuel-cladding melting and to prevent an unacceptable fraction of the core from reaching the temperature at which gross fuel failure occurs. The water level setting is far enough below normal levels that spurious HPCI system startups are avoided. The primary containment high-pressure setting is selected to be as low as reasonably achievable (ALARA) without inducing spurious HPCI system startup.

The HPCI system turbine is functionally controlled as shown on drawing nos. H-24742 through H-24749. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a pump flow signal and adjusts the turbine steam control valve so that design HPCI pump discharge flowrate is obtained. Manual control of the governor is possible in the test mode, but the governor automatically returns to automatic control upon receipt of a HPCI initiation signal.

Drawing nos. H-24744 and H-24749 show the various modes of turbine control. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the HPCI pump discharge pipeline. The governor controls the pressure applied to the hydraulic operator of the turbine control valve, which in turn controls the steam flow to the turbine. Hydraulic pressure is supplied for both the turbine control valve and the turbine stop valve by the dc motor-driven auxiliary oil pump during startup and then by the shaft-driven hydraulic oil pump when the turbine reaches ~ 2000 rpm. Should the shaft-driven oil pump malfunction, resulting in low hydraulic oil pressure, the auxiliary oil pump restarts. The operating control scheme for the auxiliary oil pump is shown on drawing no. H-24744.

Upon receipt of an initiation signal, the auxiliary oil pump starts, providing hydraulic pressure for the turbine stop valve, the turbine control valve hydraulic operator, and the C control line between the hydraulic actuator and the remote servo. Although there is no flow at first in the HPCI system, the turbine control valves are maintained closed by the HPCI turbine's electronic control system during the initial portion of the turbine start transient. This prevents rapid speedup of the turbine, thus reducing the possibility of an overspeed trip. As hydraulic oil pressure is developed, the turbine stop valve and the turbine control valve open simultaneously, and the turbine accelerates toward the speed setting of either the control governor or the speed governor, whichever is lower. As the HPCI flow increases, the flow signal adjusts the control governor setting so that design flow is maintained. The turbine is automatically or manually shut down by tripping the turbine stop valve closed if any of the following are detected.

- Turbine overspeed (automatic).
- High turbine exhaust pressure (automatic).
- Low pump suction pressure (automatic).
- RPV high water level 8 (automatic).
- HPCI isolation signal (automatic).
- Manual pushbutton.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust pipeline. Low pump suction pressure warns that cavitation and lack of coolant can cause damage to the pump, which could place it out of service. A turbine trip is initiated for these conditions so that if the causes of the abnormal conditions can be found and corrected, the system can be quickly restored to service. The trip settings are selected far enough above or below normal values so that a spurious turbine trip is unlikely, but close enough to normal values to preclude damage.

A HPCI overspeed trip automatically closes the turbine stop valve. When turbine speed decreases below a preset value, the overspeed trip mechanism auto resets, and the system auto restarts. No operator action is required. There are also several other trip signals possible, all of which reset automatically, once the trip signal clears.

There is no specific control room indication of an overspeed trip condition; however, there is a turbine stop valve open and closed light indication in the control room.

Turbine overspeed is detected by a standard turbine overspeed detection device. Two pressure transmitters/trip units are used to detect high turbine exhaust pressure. Either trip unit can initiate turbine shutdown. One pressure transmitter/trip unit is used to detect low HPCI pump suction pressure. These pressure transmitters are part of the ATTS, which is discussed in section 7.8.

High water level in the RPV indicates that the HPCI has performed satisfactorily in providing makeup water to the RPV. Further increase in level could result in HPCI turbine damage caused by gross carryover of moisture. The RPV water level 8 setting which trips the turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters/trip units that sense differential pressure are arranged so that both trip units are required to trip coincident to initiate a turbine shutdown. This level instrumentation is part of the ATTS, which is discussed in 7.8.

Operation of the gland-seal condenser components, which consist of the gland-seal condenser condensate pump (dc), the gland-seal condenser blower (dc), and the gland-seal condenser water level instrumentation, prevent outleakage from the turbine shaft seals. Startup of this equipment is automatic (drawing nos. H-24747 through H-24749), but failure does not prevent the HPCI system from providing water to the RPV.

7.3.1.2.1.3 **Bypasses and Interlocks**. To prevent the turbine pump from being damaged by overheating at reduced HPCI pump discharge flow, a pump discharge bypass is provided to route the water discharged from the pump to the suppression chamber. The bypass is controlled by an automatic, dc motor-operated valve (drawing no. H-24746). At high HPCI flow, the valve is closed; at low flow, the valve is opened. Two flow transmitters that measure the pressure difference across a flow element in the HPCI pump discharge pipeline provide the signals used for flow alarm indication and control.

Cables from one of the transmitters are routed to a trip unit (located in the MCR) which trips on a low-flow signal. Contacts from the trip unit provide a low-flow alarm and also interlock with the HPCI pump discharge high-pressure trip unit contacts to open the pump discharge bypass valve. This instrumentation is part of the ATTS, which is discussed in section 7.8.

To prevent the HPCI steam supply pipeline from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain pipeline arrangement just upstream of the turbine supply valve (drawing nos. H-24743 and H-24747). The controls position valves so that during normal operation steam line drainage is routed to the main condenser. Upon receipt of a HPCI initiation signal, the drainage path is isolated. The water

level in the steam line drain condensate pot is controlled by a level switch and a direct-acting solenoid valve which energizes to allow condensate to flow out of the pot.

During test operation, the HPCI pump discharge is routed to the CST. Two dc motor-operated valves are installed in the pump discharge to the CST pipeline. Upon receipt of a HPCI system initiation signal, the two valves close and remain closed. The valves are interlocked to close if either of the suppression chamber suction valves are not fully closed. Numerous indications pertinent to the operation and condition of the HPCI system are available to the MCR operator.

7.3.1.2.1.4 **Redundancy and Diversity**. The HPCI system is actuated either by an RPV water level 2 trip or by a drywell high-pressure trip. Both of these conditions could result from a LOCA. The redundancy of the HPCI system initiating circuits is consistent with the design of the HPCI system. A single failure does not prevent activation.

7.3.1.2.1.5 **Actuated Devices**. All automatic valves in the HPCI system are equipped with remote manual test capability so that the entire system can be operated from the MCR. Motor-operated valves are provided with appropriate limit and torque switches to turn off the motors when the fully open or fully closed positions are reached. Valves that are automatically closed upon either isolation or turbine trip signals are equipped with manual reset devices so that they cannot be reopened without operator action. All essential components of the HPCI system controls operate independently of offsite ac power.

To ensure that the HPCI system can be brought to the design flowrate within 75 s from the receipt of the initiation signal, the following maximum operating times for essential HPCI system valves are provided by the valve operation mechanisms:

- HPCI turbine steam supply valve - 50 s.
- HPCI pump discharge valves - 38 s.
- HPCI pump minimum flow bypass valve - 10 s.

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. The two HPCI steam supply line isolation valves are normally open, and they are intended to isolate the HPCI steam line in the event of a break in that line. A normally closed dc motor-operated isolation valve is located in the turbine steam supply pipeline just upstream of the turbine stop valve (drawing no. H-24745). Upon receipt of a HPCI system initiation signal, this valve opens and remains open until closed by operator action from the MCR.

Two normally keylocked open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an ac motor. The valve outside the drywell is controlled by a dc motor. The valves automatically close upon receipt of any HPCI system isolation signal. The isolation signal takes precedence over the initiating signal.
The primary element instrumentation for HPCI system isolation, which is part of the ATTS and is discussed in section 7.8, consists of the following:

A. Inside Valve 2E41-F002

1. 2E41-N671A and B pipe penetration room ambient temperature switch (trip unit) - high temperature. Isolation started as soon as activated.

2. 2E41-N670A and B HPCI equipment ambient temperature switch (trip unit) - high temperature. Isolation started as soon as activated.

3. 2E51-N665C and D differential temperature switch (trip unit) - suppression pool area ventilation air inlet and outlet high differential temperature. Isolation started after a time delay or manually upon temperature switch activation.

4. 2E41-N657A differential pressure switch (trip unit) - HPCI steam line high (+) flow. Isolation delayed 3 s.

5. 2E41-N660A differential pressure switch (trip unit) - HPCI steam line high (-) differential pressure (indicative of an instrument line break). Isolation delayed 3s.

6. 2E41-N655A and C pressure switch (trip unit) - HPCI turbine exhaust diaphragm high pressure. Both trip units must activate to isolate.

7. 2E41-N658A and C pressure switch (trip unit) - HPCI steam supply pressure low. Both trip units must activate to isolate.

8. 2E51-N666C and D suppression pool area ambient temperature switch (trip unit) - high temperature. Isolation started after a time delay or manually upon switch activation.

B. Outside Valve 2E41-F003

Instrumentation similar to that described for the inside valve causes the outside valve to isolate if the low level or high drywell initiation signal is present. Both valves can be individually actuated by manual pushbutton switches.

Three pump suction valves are provided in the HPCI system. One valve allows pump suction from the CST while the other two allow water to be taken from the suppression chamber. The CST is the preferred source. All three valves are operated by dc motors.

Upon receipt of an HPCI system initiation signal, the CST suction valve automatically opens, if closed. If the water level in the CST falls below a preselected level, the suppression chamber suction valves automatically open and the CST suction valve automatically closes. Two level switches are used to detect the CST low water level condition. Either switch can cause the suppression chamber suction valves to open and the CST suction valve to close. The suppression chamber suction valves also open automatically if a high water level is detected in the chamber. Two level transmitters monitor the water level. Cables are routed from the transmitters to the trip units located in the MCR. Either trip unit can initiate opening of the

suppression chamber suction valves. If open, the suppression chamber suction valves automatically close upon receipt of the signals that initiate HPCI steam line isolation. The suppression chamber level instrumentation is part of the ATTS, which is discussed in section 7.8.

Two dc motor-operated HPCI pump discharge valves in the pump discharge pipeline are provided (drawing nos. H-24742 and H-24746). Both valves are arranged to open upon receipt of either one of the HPCI system initiation signals. One of the pump discharge valves closes automatically upon receipt of a turbine trip signal. The other valve remains open after HPCI system initiation until closed by the operator in the MCR.

7.3.1.2.1.6 **Separation**. The HPCI system is a division II system except for the inside isolation valve E41-F002 which is an ac-powered valve supplied from a division I essential MCC. This valve is controlled by logic operated from division I 125-V-dc cabinet 2A. No single failure can prevent the automatic closure of at least one valve of the pair of isolation valves. In order to maintain the required separation, HPCI system logic relays, instruments, and manual controls are mounted so that separation from division I is maintained. Logic relays, instruments, and manual controls for outboard steam line isolation valve E41-F003 are separated from division I equipment.

7.3.1.2.1.7 **Testability**. The HPCI system is provided with a test jack so that the low reactor level or high drywell pressure one-out-of-two-taken-twice circuit can be tested completely by actuating only one instrument channel at a time. Insertion of the test plug at the logic relay panel actuates an annunciator in the MCR indicating that the HPCI system is in test status. A test signal generator is also provided in the MCR so that the turbine can be run up to the mechanical overspeed trip point for trip testing.

7.3.1.2.1.8 **Equipment Environment**. The control mechanism for the inboard isolation valve on the HPCI system turbine steam line is the only HPCI system control component located inside the primary containment that must remain functional in the environment resulting from a LOCA. Isolation valves are discussed in subsection 7.3.2. The HPCI system instrumentation and control equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate. These conditions are discussed in section 3.11.

7.3.1.2.1.9 **Operational Considerations**. The HPCI system is not required for normal operations. Under the AOO or accident conditions when it is required, initiation and control are provided automatically for at least 10 min. After that time, operator action may be required to sustain core cooling.

7.3.1.2.2 Automatic Depressurization System Instrumentation and Control

Automatically controlled safety relief valves are installed on the main steam lines inside the primary containment. The valves are dual purpose in that they relieve pressure either by normal mechanical action or by automatic action of an electric-pneumatic control system. Actuation is automatically initiated upon receipt of a signal indicating high drywell pressure and RPV water levels 1 and 3 or an RPV water level 1 signal for a period of ~ 13 min coincident with an RPV water level 3 signal, and a CS and/or RHR pumps discharge pressure permissive signal. A 130-s time delay allows the operator to delay actuation if the HPCI system is in operation. Two manual keylocked ADS inhibit switches in the main control room can be used to prevent ADS initiation during an anticipated transient without scram (ATWS) event. By inhibiting ADS, the ATWS event can be mitigated because RPV level can be lowered to enhance the effectiveness of the SLCS in shutting down the reactor. The relief by normal mechanical action is intended to prevent overpressurization of the nuclear system. An instrumented electrical backup to the mechanical relief action also exists and utilizes pressure switch logic to open SRV pilot solenoids. (See paragraph 5.2.2.2.3 for more details.) When the HPCI system is not available during a LOCA, the depressurization by automatic action of the control system is intended to reduce nuclear system pressure so that the CS system and/or LPCI can inject water into the RPV.

The automatic instrumentation and control equipment for the safety relief valves is described in this subsection. The instrumentation and control for a single safety relief valve is discussed. The other valves equipped for automatic depressurization are identical.

The control system consists of pressure and water level sensors arranged in trip systems that control a solenoid-operated pilot air valve. The solenoid-operated pilot valve controls the pneumatic pressure applied to a bellows-actuator which operates the relief valve directly. An accumulator is included with the control equipment to store pneumatic energy for safety relief valve operation. The accumulators are sized to provide at least two ADS safety relief valve actuations with the drywell at 70% design pressure. This is equivalent to four-to-five actuations of the pilot valve with the drywell at atmospheric pressure following the loss of pneumatic supply to the accumulator.

Cables from the sensors lead to the MCR where the logic arrangements are formed in cabinets. The electrical control circuitry is powered from the 125/250-V-dc power systems. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability in the event of an electrical power circuit failure. Electrical elements in the control system energize to cause opening of the safety relief valve.

7.3.1.2.2.1 **Initiating Circuits**. The pressure and level transmitters used to initiate one ADS logic are separated from those used to initiate the other logic on the same ADS valve. RPV low water level is detected by six transmitters (four for RPV level 1 detection and two for RPV level 3 detection) that measure differential pressure. Primary containment high pressure is detected by four pressure transmitters which are located outside the primary containment and inside the reactor building. The level instruments for RPV levels 1 and 3 are piped separately so that an instrument pipeline break does not inadvertently initiate automatic blowdown. Cables are routed from the transmitters to trip units (located in the MCR) which provide low water level

and high drywell pressure trips. The primary containment high-pressure signals are arranged to seal into the control circuitry. These signals must be manually reset to clear. This instrumentation is part of the ATTS, which is discussed in section 7.8.

The high drywell pressure signal will be bypassed if a sustained RPV water level 1 signal is present for a period of ~ 13 min. Upon receipt of an RPV water level 1 signal, the timer is initiated. When the timer times out, the RPV water level 1 signal must still be present in order to bypass the high drywell pressure signal. The RPV water level 1 and 3 signals must be present to activate the 130-s timer. When that timer times out, if either the RHR and/or CS pumps discharge pressure permissive signal is present, ADS will actuate. A manual reset button must be depressed to reset the bypass timer after the RPV water level 1 signal disappears. The time delay of 130 s before actuation of the ADS is long enough that the HPCI system has time to operate; yet, not so long that LPCI and the CS system are unable to adequately cool the fuel if the HPCI system fails to start. An alarm in the MCR is annunciated when either of the timers is timing. Resetting the ADS initiating signals recycles the timers.

Two manual keylocked ADS inhibit switches in the MCR can be used to prevent ADS initiation during an ATWS event. Both switches must be in the inhibit position to operationally prevent ADS initiation. An alarm in the main control room annunciates when one or both of these switches are in the inhibit position. Additionally, a white light above each switch also indicates that the switch is in the inhibit position. The combination of keylocks, alarms, and indicating lights provides assurance that ADS will not be inhibited unless the operator deliberately elects to do so. The alarms also serve to tell the operators that ADS initiation logic is susceptible to single failure when only one switch is in the inhibit position.

The system design is such that if one of the initiating signals has cleared and the ADS logic reset button is depressed, all seven valves go closed. The intent is that the valves operate as a set to provide the required blowdown rate, in addition to assuring equal torus load and temperature distribution.

7.3.1.2.2.2 **<u>Logic and Sequencing</u>**. The three initiation signals used for the ADS are RPV water level 1, primary containment (drywell) high pressure, and RHR and/or CS pumps discharge pressure permissive. In addition, RPV water level 3 is used to confirm the level 1 signal. All signals must be present to cause the safety relief valves to open (drawing nos. H-24708 and H-24709). In the event there is a sustained RPV water level 1 signal for ~ 13 min without a high drywell pressure signal, the high drywell pressure signal will be bypassed. The RPV water level 1 indicates that the fuel is in danger of becoming uncovered. The RPV water level 3 signal must also be present to initiate the ADS. The instrument trip settings are given in table 7.3-2.

Primary containment high pressure indicates a breach in the nuclear system process barrier inside the drywell. A permissive signal indicating LPCI or CS pump discharge pressure is also required. Discharge pressure on any one of the four LPCI pumps or any one of the two CS pumps is sufficient to give the permissive signal. This signal prevents automatic depressurization if LPCI and the CS system fail. If the low-pressure ECCS subsystems fail, it is preferable to maintain vessel pressure and coolant inventory. This is, of course, extremely unlikely in light of the very high availability of the overall ECCS network.

After receipt of the initiation signals and after a delay provided by timers, each of the solenoid pilot air valves is energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. The air cylinder operator holds the safety relief valve open. Lights in the MCR indicate when the solenoid-operated pilot valves are energized to open a safety relief valve.

Manual reset circuits are provided for the ADS initiation signal and primary containment high-pressure signals. By resetting these signals manually, the delay times are recycled. The operator can use the reset pushbuttons to delay or prevent automatic opening of the safety relief valves if such delay or prevention is prudent.

Two manual keylocked ADS inhibit switches in the main control room can be used to prevent ADS initiation during an ATWS event. By inhibiting ADS, the ATWS event can be mitigated, because the RPV level can be lowered to enhance the effectiveness of the SLCS in shutting down the reactor.

Control switches are available in the MCR for each safety relief valve. The open position is for manual safety relief valve operation.

Two ADS logics are provided: ADS A logic and ADS B logic (drawing no. H-24709). Division I sensors for RPV water level 1 and high drywell pressure initiate ADS A logic, and division II sensors initiate ADS B logic. Either ADS A logic or B logic actuates the solenoid pilot valve on each ADS valve. The instrumented (backup to the mechanical overpressurization protection) logic can also activate the solenoid pilot valve (paragraph 5.2.2.2.3).

The RPV water level 1 initiation setting for the ADS is selected to depressurize the RPV in time to allow adequate cooling of the fuel by LPCI or the CS system following a LOCA in which the HPCI system fails to perform its function adequately. The primary containment high-pressure setting is selected ALARA without inducing spurious initiation of the ADS. This provides timely depressurization of the RPV if the HPCI system fails to start or fails after it successfully starts following a LOCA.

The pump discharge pressure setting used as a permissive for depressurization is selected to ensure that at least one of the four LPCI pumps or one of the CS pumps has received electrical power, has started, and is capable of delivering water into the vessel. The setting is high enough to ensure that the pump delivers near rated flow without being so low as to provide an erroneous signal indicating that the pump is actually running.

7.3.1.2.2.3 **<u>Bypasses and Interlocks</u>**. It is possible for the operator to manually delay the depressurizing action by depressing the 130-s timer reset pushbutton. The operator may also interrupt the depressurization at any time by the same action. The operator would make this decision based on an assessment of other plant conditions. The high drywell pressure signal is bypassed if an RPV water level 1 signal is present for a period of ~ 13 min. The bypass logic is reset by a pushbutton located in the MCR.

The operator can manually prevent ADS initiation during an ATWS event by using two keylocked ADS inhibit switches in the main control room. This action enhances the standby liquid control system (SLCS) effectiveness in shutting down the reactor during an ATWS event.

7.3.1.2.2.4 Redundancy and Diversity. The ADS is initiated by a combination of high drywell pressure and RPV water levels 1 and 3. The initiating circuits for each of these parameters are redundant, as verified by the circuit description in this section.

7.3.1.2.2.5 Actuated Devices. All safety relief valves in the ADS are equipped with remote manual switches so that the entire system can be manually as well as automatically operated. The valves also relieve pressure by built-in mechanical action or automatically by an instrumented backup overpressurization logic that activates the pilot-operated solenoid (see paragraph 5.2.2.2.3 for more details).

7.3.1.2.2.6 Separation.

General

Refer to paragraph 7.3.1.2.

Specific

The ADS is a division I system; however, it makes use of division I and division II power. The B logic is normally connected to bus A; however, the B logic is automatically transferred to bus B on failure of bus A. The A logic is always connected to bus A. Each valve is normally connected to bus A, but each has a power monitor to automatically transfer to bus B upon power failure.

7.3.1.2.2.7 Testability.

General

Refer to paragraph 7.3.1.2.

Specific

The ADS has two trip systems, either of which can initiate automatic depressurization. Each trip system has two trip logics, both of which must trip to initiate depressurization. Four test jacks, one in each trip logic, are provided. To prevent spurious actuation of ADS during testing, only one trip logic is actuated at one time. An alarm is provided if a test plug switch along with actuation of the ADS reactor level interlock and the ac interlock (RHR or CS pump discharge pressure permissive signal) closes one of the two series relay contacts in the valve-solenoid circuit. Testing of the other trip logic and trip system is accomplished in a similar manner.

Annunciation is provided in the MCR whenever a test plug is inserted to indicate ADS in test status.

7.3.1.2.2.8 Equipment Environment. The signal cables, solenoid valves, and safety relief valve operators are the only instrumentation and control equipment for the ADS located inside the primary containment. They remain functional in the environment resulting from a LOCA. These items operate in the most severe environment resulting from a design basis LOCA (section 3.11). Gamma and neutron radiation are also considered in the selection of these items. Equipment located outside the drywell also operates in its normal and accident environments.

7.3.1.2.2.9 Operational Considerations. The instrumentation and control of the ADS are not required for normal plant operations. When automatic depressurization is required, it is initiated automatically by the circuits described in this section. No operator action is required for at least 10 min following initiation of the system.

A temperature element is installed on the safety relief valve discharge piping several feet from the valve body. The temperature element is connected to a multipoint recorder in the MCR so that a means of detecting safety relief valve leakage during plant operation is provided. When the temperature in any safety relief valve discharge pipeline exceeds a preset value, an alarm is sounded in the MCR. The alarm setting is enough above normal rated power temperatures to avoid spurious alarms, yet low enough to give early indication of safety relief valve leakage.

Two pressure-activated switches are located on the tailpipe of each safety relief valve. The first pressure switch energizes two relays. The first relay signals the plant computer each time the contact closes or opens, which in turn records the valve number, valve position, and time of each event. This relay and the second pressure switch provide an input signal to the low-low set (LLS) logic, which is discussed in subsection 7.4.4. The second relay seals in, annunciates in the MCR, and lights a light in the MCR above the individual valve control switch. The seal-in feature of the second relay can only be reset by a key-operated switch. Power for the relays and alarms is provided from the station battery system for reliability of operation.

7.3.1.2.3 CS System Instrumentation and Control

The CS system consists of two independent spray loops (drawing no. H-26018) which are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes one ac pump, appropriate valves, and the piping to route water from the suppression chamber to the RPV.

The instrumentation and control for the CS system includes the sensors, relays, wiring, and valve-operating mechanisms used to start, operate, and test the system. The sensors and valve closing mechanisms for the CS system are located in the reactor building.

Cables from the sensors are routed to the MCR where the control circuitry is assembled in electrical panels. Each CS pump is powered from a different ac bus which is capable of

receiving standby power. The power supply for automatic valves in each loop is the same as that used for the CS pump in that loop. Control power for each of the CS loops is supplied from separate dc buses. The electrical equipment in the MCR for one CS loop is located in a separate cabinet from that used for the electrical equipment for the other loop.

7.3.1.2.3.1 **Initiating Circuits**. Primary containment pressure is monitored by four pressure transmitters mounted on instrument racks outside the drywell, but inside the reactor building. Cables are routed from the transmitters to trip units, which trip on a high-pressure signal, located in the MCR. Each drywell high-pressure trip channel provides an input into the trip logic shown on drawing no. H-24739. Pipes that terminate in the reactor building allow the switches to communicate with the drywell interior. Two-out-of-four drywell pressure trip units or two-out-of-four RPV water level trip units (in a one-out-of-two-taken-twice logic) are used for initiation to ensure that no single event can prevent the initiation of the CS system. Contacts from the primary containment high-pressure signal relays are also used in the HPCI system.

RPV low water level initiation signal uses level transmitters and trip units as described for the HPCI system in paragraph 7.3.1.2.1.1. This level and drywell pressure instrumentation is part of the ATTS, which is discussed in section 7.8.

7.3.1.2.3.2 **Logic and Sequencing**. The control scheme for the CS system is illustrated on drawing nos. H-24739 through H-24741. Trip settings are given in table 7.3-3. The overall operation of the system following the receipt of an initiating signal is as follows:

A. Test bypass valves are closed and interlocked to prevent opening.

B. If normal ac power is available, the CS pumps in both spray loops start immediately.

C. If normal ac power is not available, the CS pumps in both spray loops start 12 s after receipt of the initiation signal (immediately after standby power becomes available).

D. When the RPV pressure drops to a preselected value, valves open in the pump discharge lines allowing water to be sprayed over the core.

RPV low water level indicates that the core is in danger of being overheated due to loss of coolant. Drywell high pressure indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The considerations used in establishing the RPV low water level and primary containment high-pressure settings and the instruments that provide the initiating signals are the same as those used for the HPCI system.

7.3.1.2.3.3 **Redundancy and Separation**. The CS system is completely redundant with two independent spray loops. Initiation of the system is described in paragraph 7.3.1.2.3.1. The CS pumps and discharge valves are redundant in that both logics A and B initiate starting of the pumps and opening of the valves.

7.3.1.2.3.4 **Actuated Devices**. The control arrangements for the CS pumps are shown on drawing nos. H-24739 through H-24741. The circuitry provides for the detection of normal power available so that both pumps are automatically started. Each pump can be controlled by an MCR remote switch, or by the automatic control system. A pressure transducer on the discharge pipeline from each CS pump provides a signal to the MCR to indicate the successful startup of a pump. If a CS initiation signal is received when normal ac power is not available, both CS pumps start after a 12-s time delay. (See subsection 8.3.1 for details of diesel generator loading.) The CS pump motors are provided with overload protection. Overload relays are applied to maintain power as long as possible without immediate damage to the motors or emergency power system. Valve motors that are part of the core spray system have the control contact of the thermal overload protection relay continuously bypassed during normal plant operation. These valves also have thermal overload alarms to indicate an abnormal operating condition.

Flow-measuring instrumentation is provided in each of the two CS loop discharge lines. The instrumentation provides flow indication in the MCR.

Except where specified otherwise, the remainder of this description of the CS system refers to one spray loop. The second CS loop is identical. The control arrangements for the various automatic valves in the CS system are indicated on drawing nos. H-24739 and H-24740.

Each of the valves is equipped with appropriate limit and torque switches to turn off the valve motor when the valve reaches the limits of movement. Appropriate interlocks prevent the incorrect positioning of the valves by manual action after the system has been automatically actuated. All motor-operated valves are equipped with limit switches that provide MCR indication of valve position. Each automatic valve can be operated from the MCR.

Upon receipt of an initiation signal, the test bypass valve is interlocked shut. The CS pump discharge valves are automatically opened when the reactor pressure drops to a preselected value. The setting is selected low enough so that the low-pressure portions of the CS system are not overpressurized yet high enough to open the valves in time to provide adequate cooling for the fuel. Four pressure transmitters and trip units are used to monitor reactor pressure. Trip units can initiate opening of the discharge valves on a one-out-of-two-taken-twice basis. The signal received upon automatic CS initiation overrides all other signals. This instrumentation is part of the ATTS, which is discussed in section 7.8. The full-stroke operating times of the motor-operated valves are selected to be rapid enough to ensure proper delivery of water to the RPV in a design basis accident. The full-stroke design operating times are as follows:

- Test bypass valve - standard closure rate.
- Pump suction valve - standard closure rate.
- Pump discharge valves - 9 s.[a]

The standard closure rate is based on isolating a 12-in. line in 60 s. Conversion to actual closing time can be made on this basis using the size of the line being isolated.

7.3.1.2.3.5 Separation.

General

Refer to paragraph 7.3.1.2.

Specific

The CS system consists of independent divisions I and II systems. Pump A is in division I and pump B is in division II. Two separate logics located in separate panels are used. Logic A is operated by the 125/250-V-dc bus 2A (through 125 V-dc cabinet 2B). Logics A and B initiate pumping in both loops.

7.3.1.2.3.6 Testability.

General

Refer to paragraph 7.3.1.2.

Specific

The CS system is provided with a test jack in both A and B logics. The low reactor level or drywell high-pressure one-out-of-two-taken-twice circuit can be completely tested by only actuating one instrument channel at a time. Insertion of the test plug at either logic relay panel actuates an annunciator in the MCR which indicates that the CS system is in test status.

7.3.1.2.3.7 Environmental Considerations. The only control components pertinent to CS system operation, that are located inside the primary containment, are those controlling the bypass valve for the check valve on each of the two injection lines. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate (section 3.11).

7.3.1.2.3.8 Operational Considerations. The CS system is not required for normal operations. When the system is required for accident conditions, it is initiated automatically by the circuitry described in this section. No operator action is required for at least 10 min following initiation. After this time, manual operation may be initiated.

The CS system pressure between the two pump discharge valves is monitored by a pressure switch to permit detection of leakage from the nuclear system into the CS system outside the primary containment. A detection system is provided to continuously confirm the integrity of the CS piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the bottom of the core and the inside of the

---

a. The SAFER/GESTR-LOCA analysis supports a pump discharge valve opening time of 20 s.

CS sparger pipe just outside the RPV. If the CS sparger piping is sound, this pressure difference is the pressure drop across the core. If integrity is lost, this pressure drop includes the core pressure drop and the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the MCR. Pressure in the CS pump suction pipeline is monitored by a pressure indicator that is locally mounted to permit determination of suction head and pump performance.

7.3.1.2.4 LPCI Instrumentation and Control

LPCI is an operating mode of the RHR system. LPCI is designed to provide water to the RPV following the design basis LOCA.

Drawing nos. H-26014 and H-26015 show the entire RHR system, including the equipment used for LPCI operation. The following equipment is essential for instrumentation and control:

- Four RHR system pumps.
- Pump suction valves.
- LPCI injection valves.
- RPV level transmitters and trip units.
- Drywell pressure transmitters and trip units.
- RPV pressure transmitters and trip units.

The instrumentation for LPCI operation controls other valves in the RHR system. This ensures that the water pumped from the suppression chamber by the main system pumps is routed directly to the reactor. These interlocking features are described in this subsection.

LPCI operation uses four pumps and two loops. Each loop injects into the reactor through a recirculation pump loop. Drawing nos. H-26014 and H-26015 show the location of instruments, control equipment, and LPCI components. Figure 7.3-1 shows the LPCI system. Except for the LPCI check valves inside the drywell, the components pertinent to LPCI operation are located outside the primary containment.

Power for the LPCI pumps is supplied from the 4160-V essential ac buses. Pumps 2A and 2B are powered from 4160-V essential buses 2E and 2G, respectively. Pumps 2C and 2D are powered from 4160-V essential bus 2F. Normal power for the automatic valves is supplied from 4160-V buses 1E and 1G (HNP-1-FSAR figure 8.5-3) via the HNP-1 emergency 600-V buses 1C and 1D to MCCs 2R24-S018A and B. Dedicated HNP-1 diesel generators 1A and 1C supply backup power for the 4160-V buses 1E and 1G. Alternate power for one LPCI motor-operated valve (MOV) load center is supplied from 4160-V bus 2F via 600-V bus 2D via manual transfer switch 2R26-M107 to MCC 2R24-S018A or B. Swing diesel generator 1B

supplies backup power for 4160-V bus 2F. Control power for the LPCI components comes from the dc buses.

LPCI is arranged for automatic and remote-manual operation from the MCR. Manual operation allows the operator to act independently of the automatic controls in the event of a LOCA.

7.3.1.2.4.1 **Initiating Circuits**. The two automatic initiation functions provided for LPCI are RPV water level 1 and primary containment (drywell) high pressure. Either of these functions initiates the LPCI mode of RHR.

The RPV water level 1 initiation signal for LPCI is a one-out-of-two-taken-twice circuit arrangement using relay contacts from the CS system. It is used in conjunction with the primary containment high-pressure initiation signal. The high-pressure initiation signal uses pressure transmitters/trip units such as those described for the CS system in paragraph 7.3.1.2.3.

This instrumentation is part of the ATTS, which is discussed in section 7.8.

7.3.1.2.4.2 **Logic and Sequencing**. The overall LPCI operating sequence following the receipt of an initiation signal is as follows:

A. All four main system pumps start with no delay with normal auxiliary power available. In the event that offsite power is not available and there is a LPCI initiation signal, pump 2C starts 0.5 s after diesel power is available. Pumps 2A, 2B, and 2D start 12 s after diesel power is available. The valves in the suction paths from the suppression chamber are kept open so that no automatic action is required to line up suction.

B. Valves in other systems (containment spray and RHR) are automatically positioned so that the water pumped from the suppression chamber is routed correctly.

C. When reactor pressure has dropped to a value at which the LPCI pumps are capable of injecting water into the RPV, the LPCI injection valves automatically open.

D. The LPCI loops then deliver water to the reactor pressure vessel until vessel water level is adequate to provide core cooling. The pumps will not turn off automatically but can be shut off manually when the reactor water level setpoint is satisfied.

In the descriptions of LPCI instrumentation and control that follow, drawing nos. H-26014 and H-26015 can be used to determine the schematic location of the sensors. Drawing nos. H-24732 through H-24738 can be used to determine the functional use of each sensor in the control circuitry for LPCI components. Instrument characteristics and settings are given in table 7.3-4.

7.3.1.2.4.3 Bypasses and Interlocks. To protect the main system pumps from overheating at low flowrates, a minimum flow bypass pipeline is provided that routes water from the pump discharge to the suppression chamber. An MOV controls the flow in each bypass pipeline. The minimum flow bypass valve automatically opens on sensing low flow in the common discharge lines from both pumps. The valve automatically closes when flow from the associated pump is above the low-flow setting. One transmitter/trip unit is used for each discharge line. Flow signals are derived from differential pressure transmitters which measure differential pressure across a flow element. Cables are routed from the transmitters to trip units (located in the MCR) which trip on a low differential pressure signal.

The valves that divert water for containment spray are signaled closed on receipt of a LPCI initiation signal. These valves cannot be opened by manual action unless the LPCI initiation signal is bypassed by a manually operated switch in the MCR, and the RPV water level inside the core shroud is above the level equivalent to two-thirds the core height, which indicates that the pumps are not needed for the LPCI function. Two differential pressure transmitters/trip units are used to monitor water level inside the core shroud. Each is separately piped to the RPV.

In addition to the switch discussed above, a keylock switch in the MCR allows manual override of the two-thirds core height and LPCI initiation signal permissives for the containment spray valves. This instrumentation is part of the ATTS, which is discussed in section 7.8.

7.3.1.2.4.4 Redundancy and Diversity. The LPCI mode of RHR is redundant in that two separate loops are provided with pumps A and C feeding into loop A, and pumps B and D feeding into loop B. Loops A and B are tied together by means of a cross-header with a locked valve in the header. LPCI initiation is described in paragraph 7.3.1.2.4.

7.3.1.2.4.5 Actuated Devices. The functional control arrangement for the LPCI pumps is shown on drawing no. H-24732. If offsite auxiliary ac power is available, all four LPCI system pumps start with no delay. The operator can manually control the pumps from the MCR. This permits him to use the pumps for other purposes such as containment cooling.

Two pressure transmitters are installed in each pump discharge pipeline to verify that pumps are operating following an initiation signal. Cables are routed from the transmitters to trip units located in the MCR. The pressure signal trip is used in the ADS to verify availability of low-pressure core cooling. The pressure transmitters are located upstream of the pump discharge check valves to prevent the operating-pump discharge pressure from concealing a pump failure. This instrumentation is part of the ATTS, which is discussed in section 7.8.

The main system pump motors are provided with overload protection. The overload relays maintain power on the motor as long as possible without harming the motor or jeopardizing the power system.

All automatic valves used in the LPCI function are equipped with remote-manual test capability. The entire system can be operated from the MCR. MOVs have limit switches to turn off the motors when the fully open positions are reached. Torque switches are also provided to control

valve motor forces when valves are closing. Valves that have vessel and containment isolation requirements are described in subsection 7.3.2.

The LPCI pump suction valves from the suppression pool are normally open. To reposition these valves, a keylock switch must be turned in the MCR. Upon receipt of a LPCI initiation signal, certain reactor shutdown cooling system valves and the RHR test line valves are signaled to close, although they are normally closed, to ensure that LPCI pump discharge is correctly routed. Included in this set of valves are the valves that, if not closed, would permit the main system pumps to take suction from the reactor recirculation loops, a lineup used during normal shutdown cooling system operation.

A timer similar to that used in the LPCI pump control circuitry cancels the LPCI open signal to the heat exchanger bypass valves after a 3-min delay, which is time enough to permit satisfactory start of LPCI. The signal cancellation allows the operator to control the flow through the heat exchangers for other post-accident purposes. Cancellation of the open signal does not cause the bypass valves to close.

7.3.1.2.4.6 Separation.

General

Refer to paragraph 7.3.1.2.

Specific

The LPCI mode of RHR is a division I and II system. Pumps A and D are in electrical division I, and pumps B and C are in electrical division II. Two separate logics located in separate panels are used. Logic A is operated by the 125-V-dc bus 2A, and logic B is operated by the 125-V-dc bus 2B. Logics A and B initiate flow in loops A and B.

7.3.1.2.4.7 Testability.

General

Refer to paragraph 7.3.1.2.

Specific

LPCI is provided with test jacks in each logic. The low RPV level or high drywell pressure one-out-of-two-taken-twice circuit can be completely tested by actuating only one instrument channel at a time. The other test jacks are used in the logic to facilitate testing as required. Insertion of the test plug in any jack actuates an annunciator in the MCR indicating that LPCI is in test status.

7.3.1.2.4.8 Environmental Considerations. Equipment located outside the drywell is selected in consideration of the normal and accident environments in which it must operate, as discussed in section 3.11.

7.3.1.2.4.9 Operational Considerations. LPCI is a mode of the RHR system. The pumps, valves, piping, and other equipment used for the LPCI mode are used for other modes of the RHR system. The LPCI mode is not required for normal operation.

7.3.1.3 Analysis of the Emergency Core Cooling System

7.3.1.3.1 Conformance to General Functional Requirements

In chapters 6 and 15, the individual and combined capabilities of the ECCS are evaluated. Consideration of failure in plant instrument air and loss of cooling water to vital equipment is presented in chapter 15. The safety design bases mentioned below are given in paragraph 7.3.1.1. The control equipment characteristics and trip settings described in this section were considered in the analysis of ECCS performance. The response time specification for ECCS is defined as the time from electrical signal generation to the time at which all valve movement has ceased and rated flow is entering the RPV. These times allow for single pump or emergency power source failure. Thus, diesel start time, etc., is allowed for in addition to time for RPV pressure to decay as required for the establishment of rated flow. The safety analysis uses these times and also assumes that a signal is generated from low water level for small to intermediate breaks and high drywell pressure for large breaks. The specified ECCS response times mentioned above are shown below and are discussed in subsection 6.3.3:

Function	SAFER/GESTR-LOCA Response Time
CS	≤ 31 s
LPCI	≤ 64 s
HPCI	75 s[a]

Response time testing is addressed in the Technical Specifications. Overall system response time testing comprises the measurement of control rod scram times and valve movement times which are already standard operations, plus sensor response time testing or determination. The sensors to be tested on a BWR are limited to various applications of pressure sensors and position switches. Pressure sensors and position switches are tested according to the plant surveillance procedures. Determination through means other than testing is approved for selected sensors and specific loop instrumentation for the reactor protection system (RPS), the

a. No credit is taken for HPCI operation in the SAFER/GESTR analysis to ensure that the requirements of 10 CFR 50.46 are met. However, the maximum allowable time delay from initiating signal to injection valve wide open and rated flow availability is indicated at 75 s.

isolation system, and the ECCS. The measured test results are added to the sensor or actuation instrumentation response time for comparison to the given criteria. The Technical Specifications and the Technical Requirements Manual define the instrumentation for which determination is allowed.

For the entire range of nuclear process system break sizes, the cooling systems are effective both in preventing fuel cladding melting and in preventing more than a small fraction of the reactor core from reaching the temperature at which a gross release of fission products can occur. This conclusion is valid even with significant failures in individual cooling systems because of the overlapping capabilities of the ECCS. The instrumentation and control for the ECCS satisfy the requirements of the safety design basis (paragraph 7.3.1.1.A).

The safety design basis (paragraph 7.3.1.1.B) requires that instrumentation for the ECCS responds to the potential inadequacy of core cooling regardless of the location of a breach in the nuclear system process barrier. The RPV low water level initiating function, which alone can actuate HPCI, LPCI, and CS, meets this safety design basis, because a breach in the nuclear system process barrier inside or outside the primary containment is sensed by the low water level trip channels. Because of the isolation responses of the primary containment and RPV isolation control system to a breach of the nuclear system outside the primary containment, the use of the RPV low water signal is satisfactory as the only ECCS initiating function that is completely independent of breach location.

The other major initiating function, primary containment high pressure, is provided, because the primary containment and RPV isolation control system may not be able to isolate all nuclear system breaches inside the primary containment. The primary containment high-pressure initiating signal for the ECCS provides a second reliable method for sensing losses of coolant that cannot necessarily be stopped by isolation valve action. This second initiating function is independent of the physical location of the breach within the drywell. The method used to initiate the ADS, which employs RPV low water level and primary containment high pressure, requires that the nuclear system breach be inside the drywell because of the required primary containment high-pressure signal. This control arrangement is satisfactory in view of the automatic isolation of the RPV by the primary containment and RPV isolation control system for breaches outside the primary containment, and because the ADS is required only if HPCI fails. Coincident failure of the primary containment and RPV isolation control system would be needed for nuclear system breaks outside the primary containment.

An evaluation of ECCS controls shows that no operator action is required to initiate the correct responses of the ECCS.

The alarms and indications provided to the operator in the MCR allow interpretation of any situation requiring ECCS operation and verify the response of each subsystem. Manual controls are illustrated on functional control diagrams. The MCR operator can manually initiate every operation of the ECCS.

The degree to which safety is dependent on operator judgment and response is appropriately limited by the design of the ECCS control equipment. Therefore, safety design bases listed in items C.1, C.2, and C.3 of paragraph 7.3.1.1 are satisfied.

The redundancy provided in the design of the control equipment for the ECCS is consistent with the redundancy of the cooling subsystems themselves. The arrangement of the initiating signals for the ECCS which come from common sensors, is the same as that provided by the dual trip system arrangement of the RPS. No failure of a single initiating trip channel can prevent the start of the cooling systems.

The numbers of control components provided in the design for individual cooling system components are consistent with the need for the controlled equipment. An evaluation of the control schemes for each ECCS component shows that no single control failure can prevent the combined cooling systems from providing the core with adequate cooling.

In performing this evaluation, the redundancy of components and cooling systems was considered. The functional control diagrams provided with the descriptions of cooling systems controls were used in assessing the functional effects of instrumentation failures. In the course of the evaluation, protection devices which can interrupt the planned operation of cooling system components were investigated for the results of their normal protective action, as well as the effect of maloperation on core cooling effectiveness. The only protection devices that can act to interrupt planned ECCS operation are those that must act to prevent complete failure of the component or system. Examples of such devices are the HPCI turbine overspeed trip, HPCI steam line break isolation trip, pump trips on low suction pressure, and automatically controlled minimum flow bypass valves for pumps. In every case the action of a protective device cannot prevent other redundant cooling systems from providing adequate cooling to the core.

The minimum number of trip channels and sensors, as given in tables 7.3-5, 7.3-6, 7.3-7, and 7.3-8, is sufficient to ensure correct functional performance of the ECCS. In determining the minimum number of trip channels needed to ensure functional performance, the use and redundancy of sensors in control circuitry and the redundancy of the controlled equipment in any individual cooling system were considered. For trip channels of a particular monitored variable that are arranged as dual trip systems, where both systems must trip to initiate action, the trip channels in one trip system may be inoperable without impairing performance of the system, provided that the inoperable trip system is tripped. For trip channels of different monitored variables arranged so that coincidence trips are required to produce cooling system action, proper performance of the system is possible if inoperable sensors are placed in the tripped state or if synthetic trip signals are introduced for an inoperable sensor.

Where no redundancy of trip channels is available in the controls of a cooling system component required to function if the system is to operate, functional performance is not possible unless the trip channels are operable. Where two or more sensors of a monitored variable are arranged in parallel in control circuitry, inoperability of one parallel branch does not compromise performance of the system.

It should be noted that the various degrees of redundancy in control circuitry for the components of the ECCS reflect considerations for the integrated performance of the systems. The tables referenced in this subsection consider only the functional performance of each individual cooling system. To determine the proper state in which an inoperable sensor or trip channel should be placed, the functional effect of the channel and the proper action of the controlled equipment in a LOCA are considered. The condition given in the tables for inoperable sensors provides

assurance that the essential functions of each individual ECCS subsystem are not degraded in a LOCA situation.

Because the control arrangement used for the ADS is designed to avoid spurious actuation, the information in table 7.3-6 is worthy of special consideration. The safety relief valves are controlled by two trip systems, either one of which can initiate automatic depressurization. Each trip system has two trip logics, both of which must trip to initiate depressurization. Table 7.3-6 shows that proper functional performance of the safety relief valves used for automatic depressurization is not prevented with inoperable trip channels in each trip system, provided that one trip logic in each trip system is fully operable (no failures) and that both the RPV low water level trip channel and the primary containment high-pressure trip channel for any one trip logic are not inoperable. The table further indicates that functional capability is maintained with an inoperable trip channel in the tripped state.

The conditions indicated by table 7.3-6 result in both trip systems airways remaining capable of initiating automatic depressurization. If an inoperable sensor is in the tripped state or if a synthetic trip signal is inserted in the control circuitry, automatic depressurization can be initiated when the other initiation signals are received. The prohibition against simultaneously inoperative RPV low water level and primary containment high-pressure trip channels in any one trip logic is necessary to prevent situations where a trip logic is continuously in the tripped condition. If the trip logics containing the timers are affected, the planned delay in automatic depressurization is eliminated. The trip channel conditions indicated in table 7.3-6 avoid these undesirable situations.

The conditions represented by tables 7.3-5, 7.3-6, 7.3-7, and 7.3-8 are the results of a functional analysis of each individual ECCS subsystem. Because of the redundancy in methods of supplying cooling water to the fuel in a LOCA situation, and because it is the cooling of the fuel that must be ensured in such a situation, the minimum trip channel conditions in these tables are in excess of those required operationally to ensure core cooling capability. Operational requirements for the ECCS are determined from the reliability aspects of the integrated performances of the systems when the specific characteristics of ECCS components are known.

The locations of controls where operation of ECCS components can be adjusted or interrupted have been surveyed. Controls are located in areas under the surveillance of operations personnel.

The environmental capabilities of instrumentation for the ECCS are discussed in the descriptions of the individual subsystems. Components located inside the primary containment which are essential to ECCS performance are designed to operate in the environment resulting from a LOCA.

7.3.1.3.2 Conformance to Specific Regulatory Requirements

These systems conform to Regulatory Guide 1.22; testability is discussed in detail in paragraphs 7.3.1.2.1.7, 7.3.1.2.2.7, 7.3.1.2.3.7, and 7.3.1.2.4.7. Conformance to the general design criteria is as follows:

A. Criterion 13

Each ECCS input is monitored and annunciated.

B. Criterion 19

Instrumentation and control is provided in the MCR.

C. Criterion 20

The ECCS constantly monitors the appropriate plant variables to maintain reactor coolant. It automatically initiates when the variables exceed the established setpoints.

D. Criterion 21

The ECCS is designed as two divisions of core cooling such that no single failure or operator action can prevent it from performing its safety function. The ECCS can be tested during plant operation to ensure its availability.

E. Criterion 22

The redundant portions of the ECCS are separated such that no single failure or credible natural disaster can prevent maintaining reactor coolant.

F. Criterion 23

The ECCS is designed with redundant power sources such that loss of any one power source does not disable the system.

G. Criterion 24

The ECCS has no control function.

H. Criterion 29

The ECCS is highly reliable so that it is able to accomplish its safety function in the event of anticipated operational occurrences (AOOs).

7.3.1.3.3 ECCS Conformance to IEEE 279-1971 (HPCI, ADS, CS, and LPCI)

The provisions of ECCS design which fulfill the general requirements of IEEE 279-1971 are given in the General Electric (GE) Topical Report, "Compliance of Protection Systems to Industry Criteria; General Electric BWR Nuclear Steam Supply System," NEDO-10139 (subsections 3.4.3, 3.5.2, 3.2.2, and 3.3.2, respectively). This document is supplemented by the following paragraphs:

<u>Control and Protection Interaction (IEEE 279-1971 - Paragraph 4.7)</u>

The ECCS interlocks no control systems; therefore, no failure or combination of failures in the control system can have an effect on the HPCI system.

<u>Identification (IEEE 279-1971 - Paragraph 4.22)</u>

ECCS panels, controls, instruments, and relays are identified by means of colored nameplates in conformance with the 1971 identification requirements. Controls for each subsystem are located in one section of the control panel. Relays are located in separate panels for each division and subsystem.

7.3.1.3.4 Industry Standard IEEE 338-1971

The ECCS conforms to IEEE 338-1971.

7.3.1.3.5 Industry Standards IEEE 323-1971 and IEEE 323-1974

Conformance to IEEE 323-1971 and IEEE 323-1974 is described in section 3.11.

7.3.1.3.6 Industry Standard IEEE 344-1971

Conformance to IEEE 344-1971 is described in section 3.10.

7.3.1.3.7 Regulatory Guide 1.6 (March 1971)

The ADS consists of two logic circuits. Both circuits are wired to 125 V-dc bus A. Logic B is transferable to bus B upon power failure of bus A. The B logic sensors, high drywell pressure transmitters/trip units and RPV levels 1 and 3 transmitters/trip units, are powered by dc bus B. This arrangement would protect against local failures, such as fuse failure or wire failure, and is thought to be satisfactory through proper fusing. The arrangement also provides single-failure protection.

From test data the voltage required to actuate the ADS solenoid valves is between 70 V and 90 V. However, when the bus A voltage drops below 105 V, a low-voltage annunciator is activated in the MCR. The defective power bus may then be switched off through the switch gear breaker. The ADS relays which are normally energized by bus A and which deenergize below 2 V to 13 V, then deenergize and accomplish the power bus transfer.

Since the transfer relay contacts are a break-before-make type, and since both bus A and B power lines and returns to the relay contacts are fused, adequate separation is maintained between redundant power sources.

7.3.2 PRIMARY CONTAINMENT AND RPV ISOLATION CONTROL SYSTEM

To provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barriers, the primary containment and RPV isolation control system initiates automatic isolation of appropriate lines which penetrate the primary containment whenever monitored variables exceed preselected operational limits.

A gross failure of the fuel barrier would allow the escape of fission products from the fuel. A gross failure of the nuclear system process barrier could allow the escape of gross amounts of reactor coolant. The loss of coolant could lead to overheating and failure of the fuel. For a gross failure of the fuel, the primary containment and RPV isolation control system initiates isolation of the RPV to contain released fission products. For a gross breach in the nuclear system process barrier outside the primary containment, the isolation control system acts to interpose additional barriers (isolation valve plugs) between the reactor and the breach, thus stopping the release of radioactive material and conserving reactor coolant. For gross breaches in the nuclear system process barrier inside the primary containment, the primary containment and RPV isolation control system acts to close off release routes through the primary containment barrier, thus trapping the radioactive material coming through the breach inside the primary containment.

7.3.2.1 <u>Design Basis</u>

The isolation system is designed to:

A. Limit the uncontrolled release of radioactive material to the environs by initiating timely isolation of penetrations through the primary containment structure whenever the values of monitored variables exceed preselected operational limits.

B. Provide assurance that safety design basis 7.3.2.1.A is fulfilled by responding correctly to the sensed variables over the expected range of magnitudes and rates of change.

C. Provide assurance that important variables are monitored with precision by monitoring essential variables that have spatial dependence.

D. Provide assurance that conditions indicative of a gross failure of the nuclear system process barrier are detected with sufficient timeliness and precision by deriving the system inputs, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

E. Provide assurance that the release of radioactive material and the loss of coolant as a result of a breach of a line outside the primary containment are minimal by requiring the closure time of the isolation valves to be short.

   The time required for closure of the main steam isolation valves (MSIVs) is not so short that inadvertent isolation of steam lines causes a more severe transient than

that resulting from closure of the turbine stop valves coincident with failure of the turbine bypass system. This basis ensures that the MSIV closure speed is compatible with the ability of the RPS and pressure relief system to protect the fuel and nuclear system process barrier.

F. Provide assurance that closure of group A and group B automatic isolation valves is initiated, when required, with sufficient reliability by specifying the following:

1. No single failure within the isolation control system prevents isolation action.

2. Any anticipated intentional bypass, maintenance, calibration, or test operation to verify operational availability does not impair the functional ability of the isolation control system to respond correctly to essential monitored variables.

3. The system is designed for a high probability that when any essential monitored variable exceeds the isolation setpoint, the event results in automatic isolation and does not impair the ability of the system to respond correctly as other monitored variables exceed their trip points.

4. Where a plant condition that requires isolation can be brought on by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more isolation control system channels designed to provide protection against the unsafe condition, the remaining portions of the isolation control system meet the requirements of safety design bases A, B, C, F.1, and F.2.

5. The power supplies for the primary containment and reactor pressure vessel control system are arranged so that loss of one supply cannot prevent automatic isolation when required.

6. The system is designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action requires deliberate operator action.

7. There is sufficient electrical and physical separation between trip channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly.

8. Earthquake ground motions shall not impair the ability of the primary containment and RPV isolation control system to initiate automatic isolation.

G. Ensure that the timely isolation of main steam lines is accomplished, when required, with extraordinary reliability by:

1. Deriving the motive force for achieving valve closure for one of the two tandem-mounted isolation valves in an individual steam line from a different energy source than that for the other valve.

2. Having at least one of the isolation valves in each of the steam lines not relying on continuity of any variety of electrical power for the motive force to achieve closure.

H. Reduce the probability that the operational reliability and precision is degraded by operator error by the following:

1. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables is under the control of the plant operator or supervisory personnel.

2. The means for bypassing channels, logics, or system components is under the control of the plant operator.

I. Provide the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier by manually initiating isolation of the primary containment and RPV.

J. Provide the operator with the means to assess the condition of the primary containment RPV isolation control system and to identify conditions indicative of a gross failure of the nuclear system process barrier by providing:

1. The operator with information pertinent to the status of the system.

2. Means for prompt identification of channel and trip system responses.

K. With provisions to check the operational availability of each essential channel, logic, and trip system.

7.3.2.2 System Description

7.3.2.2.1 Identification and Classification

The primary containment RPV isolation valves are grouped into three basic groups.

A. Group A isolation valves are in lines that communicate directly with the RPV and penetrate the primary containment. These lines generally have two isolation valves in series; one inside the primary containment and the other outside the primary containment.

B. Group B isolation valves are in lines that do not communicate directly with the RPV, but penetrate the primary containment and communicate with the primary containment free space. These lines have two isolation valves both outside the primary containment.

C. Group C isolation valves are in lines that penetrate the primary containment, but do not communicate directly with the RPV, the primary containment free space, or the environs. These lines require one isolation valve outside the primary containment.

The control systems required for the automatic closure of group A and group B valves are designed as Seismic Category I equipment.

The primary containment RPV isolation system includes the sensors, trip channels, switches, and remotely activated valve-closing mechanisms associated with the valves, which, when closed, effect isolation of the primary containment and/or the RPV.

It should be noted that the control systems for the group A and group B isolation valves, which close by automatic action pursuant to the safety design bases, are the main subjects of this section. However, group C remotely operated isolation valves are included, because they add to the operator's ability to effect manual isolation.

7.3.2.2.2 Initiation

Sensors providing inputs to the primary containment RPV isolation control system are not used for the automatic control of process systems, thus separating the functional control of protection systems and process systems. Channels are physically and electrically separated to ensure that a single physical event cannot prevent isolation. Channels for one monitored variable that are grouped near to each other provide inputs to different isolation trip systems.

<u>RPV Water Level Low</u>

RPV low water level signals are initiated from eight differential pressure transmitters which sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual water level in the vessel. Cables are routed from the transmitters to trip units (located in the MCR) which trip on a low RPV water level signal. Four of these trip units (two pair) have contacts which are used to indicate that the water level has decreased to RPV water level 3 isolation setting; the other four trip units (two pair) and associated four slave trip units have contacts which are used to indicate that the water has decreased to water levels 1 and 2 isolation settings, respectively.

Two lines attached to taps above and below the water level on the reactor vessel are required for the differential pressure measurement for each pair of transmitters. The four pair of lines terminate outside the primary containment and inside the reactor building; they are physically separated from each other and tap off the RPV at widely separated points. The RPV water level transmitters sense level from these pipes. This arrangement assures that no single physical event can prevent isolation on low water level (drawing no. H-26001). This level instrumentation is part of the ATTS, which is described in section 7.8.

<u>Main Steam Line Radiation Monitors</u>

Main steam line radiation is monitored by four radiation monitors, which are described in subsection 7.6.3.

Main Steam Line High Flow

High flow in each main steam line is sensed by four differential pressure transmitters which sense the pressure difference across the flow restrictor in that line. Cables are routed from the transmitter to trip units (located in the MCR) which trip on high differential pressure. Figure 7.3-2 illustrates the general arrangement of instruments used to sense the flow in a single main steam line. Figure 7.3-3 illustrates how the 16 differential pressure transmitter/trip units are combined to form four channels. Each main steam line isolation logic receives an input signal from each main steam line high-flow channel (drawing no. H-26000). This instrumentation is part of the ATTS, which is discussed in section 7.8.

Main Steam Line Chase High Temperature

High temperature in the vicinity of the main steam lines is detected by 16 resistance temperature detectors (RTDs) located along the main steam lines between the drywell wall and the turbine building. The detectors are located so that they sense any increase in temperature above ambient temperature. Cables are routed from the RTDs to trip units located in the MCR. An additional temperature sensor is located near each set of four detectors for remote temperature readout and alarm. The temperature sensors activate an alarm at high temperature and, upon loss of power, operate to give the alarm condition. The main steam line space temperature detection system is designed to detect leaks of from 1 to 10% of rated steam flow. A total of four main steam line space high-temperature channels are provided. Each main steam line isolation logic receives an input signal from one main steam line space high-temperature channel. This instrumentation is part of the ATTS, which is discussed in section 7.8.

Turbine Building Area High Temperature

Turbine building area high temperature is detected by 64 thermocouple/temperature indicating switches located in the turbine building. The turbine building area temperature detection system is designed to detect leaks of from 1 to 10% of rated steam flow. A total of four main steam line space high-temperature channels are provided. Each main steam line isolation logic receives an input signal from one main steam line space high-temperature channel.

Main Steam Line Low Pressure

Main steam line low pressure is sensed by four bourdon tube-operated pressure switches which sense pressure downstream of the outboard main steam isolation valves. The sensing point is located at the header that connects the four steam lines upstream to the turbine stop valves. Each switch is part of an independent channel. Each channel provides a signal to one isolation logic.

Condenser Vacuum Low

Condenser vacuum pressure is sensed by four pressure switches. Closure of the primary containment isolation system group 1 valves is initiated upon low condenser vacuum to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood.

Primary Containment Pressure

Primary containment pressure is monitored by four pressure transmitters which are mounted outside the drywell. Pipes that terminate in the reactor building connect the transmitters with the drywell interior. Cables are routed from the transmitters to trip units located in the MCR. The transmitters are grouped in pairs, physically separated. The trip units are electrically connected to the isolation control system so that no single event prevents isolation due to primary containment pressure. This instrumentation is a part of the ATTS, which is discussed in section 7.8.

RCIC Room High Temperature

High RCIC equipment room ambient temperature is sensed at the standby cooler by two RTDs. Cables are routed from the RTDs to trip units located in the MCR. Each RTD/trip unit is arranged as one channel. Two additional thermocouples, which are routed to temperature switches, are located near the RTDs that initiate an alarm in the MCR. Figure 7.3-4 illustrates the arrangement. All RCIC isolation functions and their arrangements are shown in detail on drawing nos. H-24750 through H-24757, and H-26023 and H-26024. The RTDs and trip units are part of the ATTS, which is discussed in section 7.8.

RCIC High Flow

High flow in the RCIC turbine steam line is sensed by two differential pressure transmitters, each of which monitors the differential pressure across an elbow installed in the RCIC turbine steam supply pipeline. Cables are routed from the transmitters to trip units (located in the MCR) which trip on high differential pressure (high flow) or low differential pressure indicative of an instrument line break. The arrangement is illustrated in figure 7.3-5. The tripping of either trip unit initiates isolation of the RCIC turbine steam line. This instrumentation is part of the ATTS, which is discussed in section 7.8.

RCIC Turbine Low Pressure

Low pressure in the RCIC turbine steam line is sensed by four pressure transmitters from the RCIC turbine steam line upstream of the isolation valves. Cables are routed from the transmitters to trip units located in the MCR. The trip units are arranged as two trip systems, both of which must trip to initiate isolation of the RCIC turbine steam line. Each trip system receives inputs from two trip units, either one of which can trip the trip system. Figure 7.3-5 illustrates this arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.8.

RCIC Turbine Exhaust Diagram High Pressure

High pressure in the RCIC turbine exhaust results in fracture of the rupture disk in the vent line which is connected to the turbine exhaust (figure 7.3-6). High pressure downstream from the rupture disk is sensed by four pressure transmitters. Cables are routed from the transmitters to trip units located in the MCR. Each set is arranged as two trip systems. Each trip system receives input signals from two trip units. Both trip units must trip to initiate isolation.

Figure 7.3-6 illustrates the arrangement. This instrumentation is part of the ATTS, which is discussed is section 7.8.

HPCI Room High Temperature

High HPCI equipment room ambient temperature is sensed at the standby cooler by two RTDs. Cables are routed from the RTDs to trip units located in the MCR. Each RTD/trip unit is arranged as one channel. Two additional thermocouples, which are routed to temperature switches, are located near the RTDs that initiate an alarm in the MCR. Figure 7.3-4 illustrates the arrangement. All HPCI isolation equipment arrangements and logic are shown on drawing nos. H-24742 through H-24749, and H-26020 and H-26021. The RTDs and trip units are part of the ATTS, which is discussed in section 7.8.

HPCI Pipe Penetration Room High Temperature

HPCI pipe penetration room high temperature is sensed by two RTDs that are appropriately located to detect a very small leak in the HPCI system steam piping, and are capable of detecting leaks equivalent to 25 gal/min. Cables are routed from the RTDs to trip units located in the MCR. Each RTD/trip unit is arranged as one channel. Two additional thermocouples are located near the RTDs that initiate an alarm in the MCR. All HPCI isolation equipment arrangements and logic are shown on drawing nos. H-24742 through H-24749, H-26020, and H-26021. The RTDs and trip units are part of the ATTS, which is discussed in section 7.8.

HPCI High Flow

High flow in the HPCI turbine steam line is sensed by two differential pressure transmitters, each of which monitors the differential pressure across an elbow installed in the HPCI turbine steam line. Cables are routed from the transmitters to trip units (located in the MCR) which trip on high differential pressure (high flow) or low differential pressure indicative of an instrument line break. The arrangement is illustrated in figure 7.3-5. The tripping of either trip unit initiates isolation of the HPCI turbine steam line. This instrumentation is part of the ATTS, which is discussed in section 7.8.

HPCI Low Pressure

Low pressure in the HPCI turbine steam line is sensed by four pressure transmitters from the HPCI turbine steam line upstream of the isolation valves. Cables are routed from the transmitters to trip units located in the MCR. The trip units are arranged as two trip systems both of which must trip to initiate isolation of the HPCI turbine steam line. Each trip system receives inputs from two trip units, either one of which can trip the trip system. Figure 7.3-5 illustrates this arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.8.

HPCI High Pressure

High pressure in the HPCI turbine exhaust results in fracture of the rupture disk in the vent line which is connected to the turbine exhaust (figure 7.3-6). High pressure downstream from the rupture disk is sensed by four pressure transmitters. Cables are routed from the transmitters to

trip units located in the MCR. Each set is arranged as two trip systems. Each trip system receives input signals from two trip units. Both trip units must trip to initiate isolation. Figure 7.3-6 illustrates the arrangement. This instrumentation is part of the ATTS, which is discussed in section 7.8.

Reactor Building Exhaust Radiation

Reactor building ventilation exhaust radiation is monitored by two sets of reactor building ventilation exhaust monitors, which are described in subsection 7.6.3. Each monitoring trip channel provides one input to each applicable isolation trip system. The channels are arranged so that any one of the channels can initiate isolation.

Refueling Floor Exhaust High Radiation

Refueling floor exhaust high radiation signals are monitored by six sets of radiation detectors located near the ventilation exhaust ductwork coming from the refueling floor. The detectors are described in paragraph 7.6.3.3. Each monitoring trip channel provides one input to each applicable isolation trip system. The channels are arranged so that any one of the channels can initiate isolation.

Reactor Water Cleanup (RWC) High Differential Flow

High differential flow in the RWC system is sensed by a differential flow switch. Flow from the reactor is sensed and compared with the sum of the flows returning to the feedwater line and to the condenser or radwaste system. This arrangement is shown in figure 7.3-7. Tripping of the differential flow switch will initiate isolation of the RWC system. Isolation signals, based upon the high differential flow, are considered nonessential for achieving either group B or C isolation. This isolation function is not an engineered safety feature. The RWC system P&ID is shown on drawing nos. H-26036 and H-26037. The high differential flow signal to the RWC isolation valves may be bypassed for up to 2 h during periods of system restoration, maintenance, or testing.

RWC High Ambient and Differential Temperature

High differential temperature in the RWC system equipment room is sensed by 12 (6 pair) RTDs as described in paragraph 5.2.7.2.3.4. Six of the RTDs monitor RWC area ventilation air inlet, and the remaining six RTDs monitor RWC area ventilation air outlet. Cables are routed from the RTDs to trip units located in the MCR. The trip units for RWC area ventilation air outlet temperature trip on high ambient temperature. The detectors are capable of detecting leaks equivalent to 25 gal/min. Analog signals from 12 trip units are further routed to six trip units which trip on high differential temperature. The arrangement is illustrated in figure 7.3-8. Each trip unit is arranged as one channel. One ambient temperature trip unit plus one differential temperature trip unit form a trip system. The tripping of either trip unit within a trip system initiates isolation. This instrumentation is part of the ATTS, which is discussed in section 7.8.

SLCS Initiation

Isolation of the RWC system upon initiation of the SLCS prevents dilution and removal of the boron solution by the RWC system. SLCS initiation begins when the standby liquid control pump receives a start signal. Initiation of the SLCS isolates the group 5 RWC outboard isolation valves.

Suppression Pool High Temperature

High ambient temperature in the suppression pool area is sensed by four RTDs. Vent air inlet and outlet high differential temperature in the suppression pool area is sensed by eight RTDs. Cables are routed from the 12 RTDs to 12 trip units located in the MCR. The eight vent air inlet and outlet trip unit analog output signals are further routed to four differential temperature trip units. The arrangement is illustrated in figure 7.3-12. One ambient temperature trip unit plus one vent air differential temperature trip unit form a trip system. A trip of either trip unit of a trip system initiates a timer in the MCR. Two trip systems with associated timers are allocated to the RCIC system, while the two remaining are allocated to the HPCI system. Isolation of the RCIC or HPCI steam lines occurs when one of the associated time delay relays runs out.

Four thermocouples, which are routed to a temperature switch, are located near the high ambient temperature RTDs; eight thermocouples (four pair routed to four differential temperature switches) are located near the high differential temperature RTDs. A trip from these switches initiates alarms in the MCR. The RTDs and trip units are part of the ATTS, which is discussed in section 7.8.

Primary Containment High Radiation

Primary containment high radiation is monitored by two radiation monitors located in the drywell, which are discussed in subsection 7.6.4 and paragraph 11.4.2.8. Each monitoring trip channel provides one input to each applicable isolation trip system.

RPV Steam Dome Pressure

RPV steam dome pressure signals are sensed by two transmitters connected to different taps on the RPV. The transmitters isolate the shutdown cooling portion of the RHR system on high pressure for equipment protection, and provide an interlock to the LPCI mode of the RHR system on low pressure.

7.3.2.2.3 Logic and Sequencing

General Logic

The basic logic arrangement is one in which an automatic isolation valve is controlled by redundant trip systems. In cases where many isolation valves close on the same signal, two trip systems control the entire group. Where just one or two valves must close in response to a special signal, two trip systems may be formed from the instruments provided to sense the

special condition. Valves that respond to the signals from common trip systems are identified in the detailed descriptions of isolation functions.

Each trip system has two trip logics, each of which receives input signals from at least one trip channel for each monitored variable. Thus, two trip channels are required for each essential monitored variable to provide independent inputs to the trip logics of one trip system. A total of four trip channels for each essential monitored variable is required for the trip logics of both trip systems. The trip actuators associated with one trip logic provide inputs into each of the trip actuator logics for that trip system. Thus, either of the two automatic trip logics associated with one trip system can produce a trip system trip. The logic is a one-out-of-two arrangement.

To initiate valve closure, the trip actuator logics of both trip systems must be tripped. The overall logic of the system is one-out-of-two-taken-twice.

The basic logic arrangement described above does not apply to group C isolation valves. Exceptions to the basic logic arrangement are made in several instances for certain group A and group B isolation valves. The reasons for this are explained in paragraph 7.3.2.2.6.

During normal operation of the isolation control system, when isolation is not required, sensor and trip contacts essential to safety are closed; trip channels, trip logics, and trip actuators are normally energized. Whenever a trip unit contact opens, its auxiliary relay deenergizes, causing contacts in the trip logic to open. The opening of contacts in the trip logic deenergizes its trip actuators. When deenergized, the trip actuators open contacts in all the trip actuator logics for that trip system. If a trip then occurs in any of the trip logics of the other trip system, the trip actuator logics for the other trip system are deenergized. With both trip systems tripped, appropriate contacts open or close in valve control circuitry to actuate the valve closing mechanism. All automatic isolation valves, regardless of their normal operating status, receive an isolation signal.

Main Steam Line Isolation Logic

The MSIVs are controlled from four logic strings as shown in figure 7.3-9. The variables initiating automatic closure of the MSIVs are:

- RPV water level 1.
- High main steam line flow.
- High main steam line tunnel temperature.
- Low main steam line pressure when in the RUN mode.
- Low condenser vacuum.
- High turbine building temperature.

Four channels are provided for each variable. One channel of each variable is connected to a particular logic to maintain channel independence and separation. One output of each logic actuator is used to control the inboard valves of all four main steam lines and a second output of each logic actuator is used to control the outboard valves of all four main steam lines. The two individual outputs of each logic actuator are obtained from relay isolated contacts.

For each valve to automatically close, both of its solenoids must be deenergized. Each solenoid receives inputs from two logics, and either input can cause deenergization of that solenoid. Hence, automatic closure of any one valve is dependent upon one-out-of-two trips to one solenoid and one-out-of-two trips to the second solenoid.

The main steam line drain valves and reactor water sample valves are controlled from the four logic strings as shown in figure 7.3-10. In this instance, the logic actuator outputs are connected in a two-out-of-two logic to each isolation valve. The inboard valve isolates if both A1 and B1 logics are tripped; similarly, the outboard valve isolates if A2 and B2 logics are tripped.

Additional interlocks exist between the main steam line drain valves and the MSIVs so that the latter are prevented from opening after an isolation unless the former are already open. This prevents a water slug from reaching the turbine when the MSIVs are opened.

Other Isolation Valves

Other inboard and outboard isolation valves are controlled from drywell high pressure and reactor low water level variables. Two drywell pressure sensors are combined with two water level sensors to form a hybrid one-out-of-two-taken-twice network for the inboard isolation valves. Two other drywell high pressure and two other water level sensors are used in a second hybrid network for the outboard isolation valves. This logic is shown on drawing no. H-24701. These same drywell pressure-water level logics are used with process radiation monitoring signals to produce other isolation actions including initiation of the standby gas treatment system (SGTS). In this instance, one process radiation monitor upscale signal is used with the inboard valves and a second process radiation monitor upscale signal is used with the outboard valves. A downscale alarm is given in the event of an equipment malfunction which results in the loss of either monitoring signal.

RWC Isolation Logic

The RWC system isolation valves from the reactor are controlled by two logics using high differential flow, high area temperature, high area differential temperature, and RPV water level 2 isolation signals. One logic controls the inboard valve, and a second logic controls the outboard valve of the cleanup loop. Isolation signals, based on the high differential flow, are considered nonessential for achieving either a group B or C isolation. This isolation function is not an engineered safety feature.

SLCS initiation isolates the outboard isolation valve.

7.3.2.2.4 Bypass and Interlocks

Isolation of the four main steam lines, main steam line drain, and reactor water sample lines due to low steam line pressure is bypassed when the mode switch is not in the RUN mode. Isolation of these valves due to low condenser vacuum can be manually bypassed when the turbine stop valves are < 90% open.

7.3.2.2.5 Redundancy and Separation

The physical and electrical arrangement of the primary containment reactor pressure vessel isolation control system was selected so that no single physical event prevents isolation. The location of group A and group B valves inside and outside the primary containment provides assurance that the control system for at least one valve on any line penetrating the primary containment remains capable of automatic isolation. Electrical cables for isolation valves in the same line are routed separately.

7.3.2.2.6 Actuated Devices

The following paragraphs itemize the actuated isolation valves according to sensor. The isolation trip settings of the primary containment RPV isolation control system are listed in table 7.3-9. The functions that initiate automatic isolation are itemized in ***Technical Requirements Manual (TRM) table T7.0-1 (incorporated by reference into the FSAR)*** in terms of the lines that penetrate the primary containment. This latter table includes all lines of concern for isolation purposes. Although this section is concerned with the electrical control systems that initiate isolation to prevent direct release of radioactive material from the primary containment or nuclear system process barrier, the additional information given in ***TRM table T7.0-1*** can be used to assess the overall (electrical and mechanical) isolation effectiveness of each system having lines which penetrate the primary containment. Isolation function and trip settings used for the electrical control of isolation valves in fulfillment of the previously stated safety design bases are discussed in the following paragraphs.

A. RPV Low Water Level (Levels 1, 2, and 3) (See isolation group signals in ***TRM table T7.0-1***.)

   A low water level in the reactor vessel could indicate that either reactor coolant is being lost through a breach in the nuclear system process barrier or that the normal supply of reactor feedwater has been lost and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. Reactor vessel low water level initiates closure of various group A valves and group B valves. The closure of group A valves is intended to either isolate a breach in any of the lines in which valves are closed or conserve reactor coolant by closing off process lines. The closure of group B valves is intended to prevent the escape of radioactive material from the primary containment through process lines which are in communication with the primary containment free space.

Three RPV low water level isolation trip settings are used to complete the isolation of the primary containment and the RPV. The highest RPV low water level isolation trip setting, RPV water level 3, scrams the reactor and initiates closure of all group A and group B valves in major process lines, except for the main steam lines, the main steam line drain lines, the reactor water sample lines, and the RWC lines. The RWC lines isolate at RPV water level 2. The main steam lines are left open to allow the removal of heat from the reactor core. The lowest RPV water level isolation trip setting, RPV water level 1, completes the isolation of the primary containment and RPV by initiating closure of the MSIVs and any other group A or B valves that must be shut to isolate minor process lines.

The first low water level setting, which is coincidentally the same as the RPV low water level scram setting, was selected to initiate isolation at the earliest indication of a possible breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious isolation. Isolation of the following lines is initiated when RPV low water level falls to this first setting:

1. RHR reactor shutdown cooling supply.[a]
2. Drywell-to-torus differential pressure system isolation valves.[a]
3. Drywell equipment drain discharge.
4. Drywell floor drain discharge.
5. Drywell purge inlet[a].
6. Drywell main exhaust.[a]
7. Suppression chamber exhaust valve bypass.[a]
8. Suppression chamber purge inlet.[a]
9. Suppression chamber main exhaust.[a]
10. Drywell exhaust valve bypass.[a]
11. Drywell and suppression chamber supply line.[a]
12. Drywell and suppression chamber makeup line (one valve open, one valve closed).
13. H_2O_2 analyzer and fission products monitoring systems.
14. Traversing incore probe (TIP) tubes.
15. Drywell pneumatic system from drywell.
16. Drywell post-accident ventilation.
17. Torus post-accident ventilation.
18. Condensate pump suction from torus.

The second lower RPV low water level isolation setting, RPV water level 2, is selected low enough to avoid isolation of RWC lines due to a level transient caused by void collapse following a scram from normal power levels, yet high enough to complete isolation in time for the operation of the HPCI and RCIC systems in the event of a break.

The lowest of the RPV low water level isolation settings, RPV water level 1, was selected low enough to allow the removal of heat from the reactor for a predetermined time following the scram and high enough to complete isolation in time for the operation of the HPCI and RCIC systems in the event of a break in the nuclear system process barrier. The lowering of the MSIV isolation water level is

another means to mitigate the induced loads of subsequent safety relief valve actuations. A delayed MSIV isolation allows more steam to be released from the reactor prior to safety relief valve actuation. The subsequent pressurization rate following MSIV isolation is also reduced because of the lower decay heat rate at this later time.

This level setting is low enough that partial losses of feedwater supply would not unnecessarily initiate full isolation of the reactor, thereby disrupting normal plant shutdown or recovery procedures. Isolation of the following lines is initiated when the reactor vessel water level falls to RPV water level 1 (See isolation group signals in ***TRM table T7.0-1***.):

1. All four main steam lines.
2. Main steam line drain.[a]
3. Reactor water sample line.[a]

B. Main Steam Line High Radiation

High radiation in the vicinity of the main steam lines could indicate a gross release of fission products from the fuel. High radiation near the main steam lines initiates isolation of the reactor water sample line,[a] drywell-to-torus differential pressure valve line, main condenser mechanical vacuum pump line, and steam packing exhauster line.

The high-radiation trip setting is selected high enough above background radiation levels to avoid spurious isolation, yet low enough to promptly detect a gross release of fission products from the fuel. Further information regarding the high-radiation setpoint is available in subsection 7.6.3.

C. Main Steam Line High Flow (See isolation group signals in ***TRM table T7.0-1***.)

Main steam line high flow could indicate a break in a main steam line. The automatic closure of various group A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of the main steam line high flow, the following lines are isolated:

1. All four main steam lines.
2. Main steam line drain.[a]
3. Reactor water sample line.[a]

The main steam line high-flow trip setting was selected high enough to permit the isolation of one main steam line for test at rated power without causing an automatic isolation of the rest of the steam lines yet low enough to permit early detection of a gross steam line break.

a. Closed during normal power operation.

D. Main Steam Line Space High Temperature (See isolation group signals in ***TRM table T7.0-1***.)

High temperature in the space in which the main steam lines are located outside of the primary containment could indicate a breach in a main steam line. The automatic closure of various group A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperatures occur in the main steam line space, the following pipelines are isolated:

1. All four main steam lines.
2. Main steam line drain.[a]
3. Reactor water sample line.[a]

The main steam line space high-temperature trip is set far enough above the temperature expected during operations at rated power to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

E. Low Steam Pressure at Turbine Inlet (See isolation group signals in ***TRM table T7.0-1***.)

Low steam pressure upstream of the turbine stop valves while the reactor is operating could indicate a malfunction of the pressure regulator in which the turbine control valves or turbine bypass valves operate fully. This action could cause rapid depressurization of the nuclear system. From part-load operating conditions, the rate of decrease of nuclear system saturation temperature could exceed the design rate of change of vessel temperature. A rapid depressurization of the reactor vessel while the reactor is near full power could result in undesirable differential pressures across the channels around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without adequate preventive action, could require thorough vessel analysis or core inspection prior to returning the reactor to power operation. To avoid the time-consuming requirements following a rapid depressurization, the steam pressure at the turbine inlet is monitored and, upon falling below a preselected value with the reactor in the RUN mode, initiates isolation of the following lines:

1. All four main steam lines.
2. Main steam drain line.[a]
3. Reactor water sample line.[a]

The low steam pressure isolation setting was selected far enough below normal turbine inlet pressures to avoid spurious isolation yet high enough to provide timely

---

a. Closed during normal power operation.

detection of a pressure regulator malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, this discussion is included here to make the listing of isolation functions complete.

F. Primary Containment (Drywell) High Pressure (See isolation group signals in ***TRM table T7.0-1***.)

High pressure in the drywell could indicate a breach of the nuclear system process barrier inside the drywell. The automatic closure of various containment isolation valves prevents the release of significant amounts of radioactive material from the primary containment. Automatic closure of selected RPV isolation valves prevents possible addition to the overpressure. Upon detection of a high drywell pressure, the following lines are isolated:

1. Drywell equipment drain discharge.
2. Drywell floor drain discharge.
3. TIP tubes (group A).
4. Drywell purge inlet.[a]
5. Drywell main exhaust.[a]
6. Suppression chamber exhaust valve bypass.[a]
7. Suppression chamber purge inlet.[a]
8. Suppression chamber main exhaust.[a]
9. Drywell exhaust valve bypass.[a]
10. H_2O_2 analyzer and fission product monitoring systems sample lines.
11. Drywell and suppression chamber supply line.[a]
12. Drywell and suppression chamber makeup line (one valve open, one valve closed).
13. Drywell pneumatic system from drywell.
14. TIP guide tubes.
15. Torus vacuum drag.
16. HPCI/RCIC turbine exhaust vacuum breakers.
17. Drywell-to-torus differential pressure suction.[a]

The primary containment high-pressure isolation setting was selected to be as low as possible without inducing spurious isolation trips.

G. RCIC Equipment Room and Suppression Pool Area High Temperature (See isolation group signals in ***TRM table T7.0-1***.)

High temperature in the RCIC equipment room or in the suppression pool area could indicate a break in the RCIC steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high ambient temperature is sensed in the suppression pool area or

a. Closed during normal power operation.

high differential temperature is sensed between the inlet and outlet ducts that ventilate the suppression pool area, an alarm is actuated in the control room and a timer is initiated. A separate alarm in the MCR is actuated upon timer initiation, providing notification of possible system isolation. If the high temperature or high differential temperature is not reduced below the trip point before the timer runs out, the RCIC steam line is isolated. When high ambient temperature is sensed at the RCIC equipment compartment cooler, an alarm is actuated in the control room. The high ambient temperature signal will isolate the RCIC steam line. The high ambient and differential temperature isolation settings were selected far enough above anticipated normal operational levels to avoid spurious operation but low enough to provide timely detection of a RCIC turbine steam line break. The timer setting is established to eliminate isolations due to a break in the main steam system in the nearby pipe chase.

H. RCIC Turbine High Steam Flow (See isolation group signals in ***TRM table T7.0-1***.)

RCIC turbine high steam flow could indicate a large break in the RCIC turbine steam line. The automatic closure of the RCIC steam line valves after a 3-s time delay prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The RCIC turbine high steam flow trip and time delay settings were selected high enough to avoid spurious isolation; i.e., above the high steam flowrate encountered during turbine starts. The setting was selected low enough to provide timely detection of an RCIC turbine steam line break.

The logic arrangement used for this function is an exception to the usual logic requirements since high steam flow is the second method of detecting a RCIC turbine steam line break.

I. RCIC Turbine Steam Line Low Pressure (See isolation group signals in ***TRM table T7.0-1***.)

Low pressure in the RCIC steam line could indicate a break in the RCIC steam line. Therefore, the RCIC steam line isolation valves are automatically closed. The steam line low-pressure function is provided so that in the event a gross rupture of the RCIC steam line occurred upstream from the high-flow sensing location, thus negating the high-flow indication function, isolation would be affected on low pressure. The isolation setpoint is chosen at a pressure below that which the RCIC turbine can effectively operate.

J. RCIC Turbine Exhaust Diaphragm High Pressure (See isolation group signals in ***TRM table T7.0-1***.)

High pressure in the RCIC turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The RCIC exhaust line is protected from overpressure by the rupture disks. In the event of a rupture disk actuation, the steam line isolation valves are automatically closed to isolate the RCIC steam supply, thereby preventing the loss of reactor

steam to the torus room. The turbine exhaust pressure trip setting is selected high enough to avoid isolation of the RCIC if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

K. HPCI Equipment Room and Suppression Pool Area High Temperature (See isolation group signals in ***TRM table T7.0-1***.)

High temperature in the HPCI equipment room or in the suppression pool area could indicate a break in the HPCI system turbine steam line. The automatic closure of the HPCI steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high ambient temperature is sensed in the suppression pool area or high differential temperature is sensed between the inlet and outlet ducts which ventilate the suppression pool area, an alarm is activated in the MCR and a timer is initiated. A separate alarm in the MCR is actuated upon timer initiation, providing notification of possible system isolation. If the high temperature or high differential temperature is not reduced below the trip point before the timer runs out, the HPCI steam line is isolated. When high ambient temperature is sensed at the HPCI equipment compartment cooler, an alarm is actuated in the control room. The high ambient temperature signal will isolate the HPCI steam line. The high ambient and differential temperature isolation settings were selected far enough above anticipated normal HPCI system operational levels to avoid spurious isolation but low enough to provide timely detection of a HPCI turbine steam line break. The timer setting is established to eliminate spurious isolations which might occur when switching from normal ventilation to standby ventilation.

L. HPCI Turbine High Steam Flow (See isolation group signals in ***TRM table T7.0-1***.)

HPCI turbine high steam flow could indicate a break in the HPCI turbine steam line. The automatic closure of the HPCI steam line isolation valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of HPCI turbine high steam flow, the HPCI turbine steam line is isolated after a 3-s time delay. The high steam flow trip and time delay setting were selected high enough to avoid spurious isolation; i.e., above the high steam flowrate encountered during turbine starts. The setting was selected low enough to provide timely detection of an HPCI turbine steam line break.

The logic arrangement used for this function is an exception to the usual logic requirements since high steam flow is the second method of detecting a HPCI steam line break.

M. HPCI Turbine Steam Line Low Pressure (See isolation group signals in ***TRM table T7.0-1***.)

Low pressure in the HPCI steam line could indicate a break in the HPCI steam line. Therefore, the HPCI steam line isolation valves are automatically closed. The

steam line low-pressure function is provided so that in the event a gross rupture of the HPCI steam line occurred upstream from the high-flow sensing location, thus negating the high-flow indicating function, isolation would be effected on low pressure. The isolation setpoint is chosen at a pressure below that at which the HPCI turbine can effectively operate.

N. HPCI Turbine Exhaust Diaphragm High Pressure (See isolation group signals in ***TRM table T7.0-1***.)

High pressure in the HPCI turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The HPCI exhaust line is protected from overpressure by the rupture disks. In the event of a rupture disk actuation, the MSIVs are automatically closed to isolate the HPCI steam supply, thereby preventing the loss of reactor steam to the torus room. The turbine exhaust pressure trip setting is selected high enough to avoid isolation of the HPCI if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

O. Reactor Building/Refueling Floor Ventilation Exhaust High Radiation (See isolation group signals in ***TRM table T7.0-1***.)

High radiation in the reactor building or refueling floor ventilation exhaust could indicate a breach of the nuclear system process barrier inside the primary containment which would result in increased airborne radioactivity levels in the primary containment exhaust to the secondary containment. The automatic closure of certain group B valves acts to close off release routes for radioactive material from the primary containment into the secondary containment (reactor building). Reactor building ventilation exhaust high radiation initiates isolation of the following lines:

1. Drywell purge inlet.[a]
2. Drywell main exhaust.[a]
3. Suppression chamber exhaust valve bypass.[a]
4. Suppression chamber purge inlet.[a]
5. Suppression chamber main exhaust.[a]
6. Drywell exhaust valve bypass.[a]
7. Drywell and suppression chamber supply line.[a]
8. Drywell and suppression chamber makeup line (one valve open, one valve closed).
9. Drywell pneumatic system from drywell.
10. Torus vacuum drag.
11. Drywell-to-torus differential pressure suction.[a]
12. H_2O_2 analyzer.
13. Fission products monitoring system.
14. Drywell post-accident ventilation.

a. Closed during normal power operation.

The high-radiation trip setting selected is far enough above background radiation levels to avoid spurious isolation, but low enough to provide timely detection of nuclear system process barrier leaks inside the primary containment. Because the primary containment high-pressure isolation function and the RPV low water level isolation function are adequate in effecting appropriate isolation of the above lines for gross beaks, the reactor building ventilation exhaust high-radiation isolation function is provided as a third redundant method of detecting breaks in the nuclear system process barrier significant enough to require automatic isolation.

P. Cleanup System Equipment Room High Ambient and High Differential Temperature (See isolation group signals in ***TRM table T7.0-1***.)

High ambient or differential temperature in the cleanup system equipment room could indicate a break in the RWC system line carrying high-temperature water. When high differential temperature is sensed between the inlet and outlet ducts which ventilate the cleanup system room or high temperature in the room is sensed, the RWC system is automatically isolated. The high ambient and differential temperature trip settings are selected high enough to avoid spurious isolation, yet low enough to provide timely detection and isolation of a break in the RWC system.

Q. Cleanup System High Differential Flow

High differential flow in the RWC system, measured between a point immediately outside the primary containment on the discharge side of the pump and points downstream from the filter-demineralizers, could indicate a break between these points. The automatic closure of the cleanup system isolation valves prevents excessive loss of reactor coolant and significant amounts of radioactive material. A break downstream from the filter-demineralizers would be less consequential because of the low radioactivity of the water at this point. The high differential flow trip setting was selected high enough to avoid spurious isolations yet low enough to provide timely detection and isolation.

Isolation signals based on the high differential flow are considered nonessential for achieving either a group B or C isolation. This isolation function is not an engineered safety feature.

R. Turbine Condenser Low Vacuum (See isolation group signals in ***TRM table T7.0-1***.)

Main turbine condenser low vacuum could indicate a leak in the condenser. Initiation of the automatic closure of various group A valves prevents excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of turbine condenser low vacuum the following lines are isolated:

---

a. Closed during normal power operation.

1. All four main steam lines.
2. Main steam line drain.
3. Reactor water sample line.

The turbine condenser low vacuum trip setting is selected far enough below the normal operating vacuum (higher pressure) to avoid spurious isolation, yet high enough to provide an isolation signal prior to the rupture of the condenser and subsequent loss of reactor coolant and release of radioactive material.

S. Primary Containment High Radiation (See isolation group signals in ***TRM table T7.0-1***.)

High radiation in the primary containment could indicate a breach of the nuclear system process barrier inside the primary containment which would result in increased airborne radioactivity levels in the primary containment. The automatic closure of the following group B isolation valves will close off release routes for radioactive material from primary containment to the secondary containment:

1. Drywell purge inlet.[a]
2. Drywell main exhaust.[a]
3. Suppression chamber purge inlet.[a]
4. Suppression chamber main exhaust.[a]

The primary containment high radiation signal isolation logic provides a redundant means to protect against substantial releases of radiation to the atmosphere due to an accident. The high radiation setpoint is determined such that the dose will not exceed the general emergency guidelines (EPA-400-R-92-001, October 1991) of 1 rem total effective dose equivalent or 5 rem thyroid at the site boundary.

7.3.2.2.7 Testability

The primary containment RPV isolation control system is testable during reactor operation. Isolation valves can be tested to ensure that they are capable of closing by operating manual switches in the MCR and observing the position lights and any associated process effects. The channel and trip system responses can be functionally tested by applying test signals to each channel and observing the trip system response. Testing of the MSIVs is discussed in subsection 5.5.5. (See also figure 7.3-11 and drawing nos. H-24702 through H-24705.)

7.3.2.2.8 Supporting Systems

The power for the channels and logics of the isolation control system is supplied from the RPS motor-generator sets. Isolation valves receive power from essential buses. Power for the operation of two valves in a line is fed from different sources. In most cases, one valve is

---

a. Closed during normal power operation.

powered from an ac bus of appropriate voltage and the other valve is powered by dc from the plant batteries. The MSIVs use ac, dc, and pneumatic pressure in the control scheme. ***TRM table T7.0-1*** lists the power supply for each isolation valve.

7.3.2.2.9 Equipment Environment

Motor operators for valves inside the primary containment are of the totally enclosed type; those outside the primary containment have weatherproof type enclosures. Solenoid valves, whether used for direct valve isolation or as an air pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for normal operations. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high radiation areas have radiation-resistant insulation. Shielded cables are used where necessary to eliminate interference from magnetic fields.

Special consideration is given to isolation requirements during a LOCA inside the drywell. Components of the primary containment RPV isolation control system that are located inside the primary containment and that must operate during a LOCA are the cables, control mechanisms, and valve operators of isolation valves inside the drywell. These isolation components are required to be functional in a LOCA environment.

Electrical cables are selected with insulation designed for this service. Closing mechanisms and valve operators are considered satisfactory for use in the isolation control system only after completion of environmental testing under LOCA conditions or submission of evidence from the manufacturer describing the results of suitable prior tests.

Verification that the isolation equipment was designed, built, and installed in conformance to the specified criteria is accomplished through quality control and performance tests in the vendor's shop or after installation at the plant before startup, during startup, and thereafter during the service life of the equipment.

7.3.2.2.10 Operational Considerations

TRM table T7.0-1 itemizes the type of closing device to be provided. The design closure times for each isolation valve intended for use in automatic or remote manual isolation of the primary containment or RPV are provided in ***TRM table T7.0-1*** or the Plant Hatch pump and valve inservice testing program. To meet the requirement that automatic group A valves be fully closed in time to prevent the RPV water level from falling below the top of the active fuel as a result of a break of the line which the valve isolates, the valve closing mechanisms are designed to give the minimum closing rates specified. In many cases, a standard closing rate of 12 in./min is adequate to meet isolation requirements. Using the standard rate, a 12-in. valve is closed in 60 s. Conversion to actual closing time can be made by using the size of the line to be isolated. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a standard closure rate (12 in./min) is adequate for the automatic closing devices on group B isolation valves.

Motor operators for group A and group B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve closing rates were considered in designing motor operators. Appropriate torque and limit switches are used to ensure proper valve seating. Handwheels, which are automatically disengaged from the motor operator when the motor is energized, are provided for local hand operation.

Direct solenoid-operated isolation valves and solenoid air pilot valves are chosen with electrical and mechanical characteristics which make them suitable for the service for which they are intended. Appropriate watertight or weathertight housings are used to ensure proper operation under accident conditions.

The MSIVs are spring/pneumatic-closing, pneumatic-opening, piston-operated valves designed to close upon loss of pneumatic pressure to the valve operator. This is fail-safe design. The control arrangement is shown in figure 7.3-11 and drawing no. H-24703. Closure time for the valves is between 3 and 5 s. Each valve is piloted by two, three-way, packless, direct-acting, solenoid- operated pilot valves, one powered by ac, the other by dc. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve closing in the event of failure of the normal air supply system.

The valve pilot system and the pneumatic lines (drawing no H-24703) are arranged so that when one or both solenoid-operated pilot valves are energized, normal air supply provides pneumatic pressure to the air-operated pilot valve to direct air pressure to the main valve pneumatic operator. This overcomes the closing force exerted by the spring to keep the main valve open. When both pilots are deenergized, as would be the result of both trip systems tripping or placing the manual switch in the closed position, the path through which air pressure acts is switched so that the opposite side of the valve operator is pressurized, thus assisting the spring in closing the valve. In the event of air supply failure, the loss of air pressure causes the air-operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the air stored in the accumulator and by the spring.

Air pressure, acting alone, and the force exerted by the spring, acting alone, are each capable of independently closing the valve. The isolation valves inside the primary containment (inboard) are designed to close under either pneumatic pressure or spring force with the vented side of the piston operator at the containment peak accident pressure. (The outboard valve is exactly the same design, although it is subjected only to atmospheric pressures.) The accumulator volume was chosen to provide enough pressure to close the valve when the pneumatic supply to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closing.

A separate, single, solenoid-operated pilot valve with an independent test switch is included to allow manual testing of each isolation valve from the MCR. The testing arrangement is designed to give a slow closure of the isolation valve being tested to avoid rapid changes in steam flow and nuclear system pressure. Slow closure of a valve during testing requires 50 to 60 s. The valve mechanical design is discussed further in subsection 5.5.5.

All automatic isolation valves receive an isolation signal regardless of their normal operating status. The control system for each isolation valve is designed to provide closure of the valve in time to prevent uncovering the fuel as a result of a break in the line which the valve isolates. The control systems for group A and group B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline valves of applicable regulations.

All automatic group A and group B valves and remotely operable group C valves can be closed by manipulating switches in the MCR, thus providing the operator with means independent of the automatic isolation functions.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the MCR to reopen a valve which was automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions which initiated isolation have cleared.

A trip of an isolation control system channel is annunciated in the MCR so that the operator is immediately informed of the condition. The response of isolation valves is indicated by open-closed lights. All motor-operated group A and group B isolation valves have two sets of open-closed lights. One set is located near the manual control switches for the control of each valve from the control room. A second set is located in a separate central isolation valve position display in the control room. The positions of air-operated isolation valves are displayed in the same manner as MOVs.

Inputs to annunciators, indicators, and the process computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output.

7.3.2.3 Analysis

The primary containment reactor pressure vessel isolation control system, in conjunction with other safety systems, is designed to provide timely protection against the onset and consequences of accidents involving the gross release of radioactive material from the fuel and nuclear system process barriers. It is the objective of chapter 15 to identify and evaluate postulated events resulting in gross failure of the fuel barrier and the nuclear system process barrier. The consequences of such gross failures are described and evaluated in that chapter.

Design procedure has been to select tentative isolation trip settings that are far enough above or below normal operating levels that spurious isolation and operating inconvenience are avoided. It is then verified by analysis that the release of radioactive material following postulated gross failures of the fuel and nuclear system process barrier is kept within acceptable bounds. Trip setting selection is based on operating experience and constrained by the safety design and the safety analyses. Trip setpoints for the ATTS instruments account for instrument accuracy, calibration accuracy, and drift in accordance with Regulatory Guide 1.105

and the Instrument Society of America standards. In all cases except that of the MSIVs the concept of isolation rate employed in the safety analysis does not invoke sensor response time.

This follows from the fact that the relevant safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For dc-operated valves a 3-s delay is assumed before the valve starts to move. For the ac-operated valves it is assumed that the ac power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 s is assumed before the valve starts to move.

In addition to the pipe break, the failure of the dc-operated valve is assumed; thus, the signal delay (sensor response) is concurrent with the 13-s diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the delay (13 s). It follows that checking the valve speeds and the time (13 s) for emergency power establishment cover response time testing for the isolation functions.

For the MSIVs, the applicable instrumentation response times are as follows:

Function	Response Time
RPV water level 1	≤ 1.0 s
Flow - high	≤ 0.5 s

The above response times are the isolation actuation instrumentation response times. The sensor is eliminated from response time testing for these MSIV actuation logic circuits. Response time testing includes the trip unit and relay logic portions of the instrumentation channel. The response time for the channel sensor may be determined through means other than testing. The measured (test) results are added to the sensor response time for comparison to the given criteria. Valve movement times shown in ***TRM table T7.0-1*** are added to the instrumentation response time to obtain the isolation system response time.

Chapter 15 shows that the actions initiated by the primary containment RPV isolation control system, in conjunction with other safety systems, are sufficient to prevent releases of radioactive material from exceeding the guide values of published regulations. Because the actions of the system are effective in restricting the uncontrolled release of radioactive materials under accident situations, the primary containment RPV isolation control system meets the precision and timeliness requirements of design basis 7.3.2.1.A.

The primary containment RPV isolation control system meets the precision and timeliness requirements of safety design basis A using instruments with the characteristics described in table 7.3-9. Therefore, it is concluded that design basis 7.3.2.1.B is met.

Temperatures in the spaces occupied by the various steam lines outside the primary containment are the only essential variables of significant spatial dependence that provide inputs to the primary containment RPV isolation control system. The large number of temperature sensors and their dispersed arrangement near the steam lines requiring this type of break protection provide assurance that a significant break is detected rapidly and accurately.

One of the four groups of temperature switches is located in the ventilation exhaust from the steam line space between the drywell wall and the secondary containment wall. This ensures that abnormal air temperature increases are detected regardless of leak location in that space. It is concluded that the number of sensors provided for steam line break detection satisfies design basis 7.3.2.1.C.

Because the primary containment RPV isolation control system meets the timeliness and precision requirements of design basis 7.3.2.1.A by monitoring variables that are true, direct measures of operational conditions, it is concluded that design basis 7.3.2.1.D is satisfied.

Chapter 15 evaluates a gross breach in a main steam line outside the primary containment during operation at rated power. The evaluation shows that the main steam lines are automatically isolated in time to prevent both a release of radioactive material in excess of the guideline values of published regulations and to prevent the loss of coolant from being great enough to allow uncovering of the core. These results are true even if the longest closing time of the valves is assumed. The time required for automatic closure of the MSIVs meets the requirements of design basis 7.3.2.1.E.

The shortest closure time of which the MSIVs are capable is 3 s. The transient resulting from a simultaneous closure of all MSIVs in 3 s during reactor operation at rated power is considerably less severe than the transient resulting from inadvertent closure of the turbine stop valves (which occurs in a small fraction of 1 s) coincident with failure of the turbine bypass system. This meets design basis 7.3.2.1.E.

The items of safety design bases 7.3.2.1.F, G, and H must be fulfilled for the primary containment RPV isolation control system to meet the design reliability requirements of safety design basis 7.3.2.1.A.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the MCR to reopen a valve which has been automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions which initiated isolation have cleared. This is the equivalent of a manual reset and meets design basis 7.3.2.1.F.6. The remainder of the reliability requirement is met by a combination of logic arrangement, sensor redundancy, wiring scheme, physical isolation, power supply arrangement, and environmental capabilities. These subjects are discussed in the following paragraphs.

Because essential variables are monitored by four trip channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate closure of automatic isolation valves, no single failure, maintenance operation, calibration operation, or test can prevent the system from initiating valve closure. An analysis of the isolation control system shows that the system does not fail to respond to essential variables as a result of single electrical failures such as short circuits, ground, and open circuits. A single trip system trip is the result of these failures. Isolation is initiated upon a trip of the remaining trip system. For some of the exceptions to the usual logic arrangement, a single failure could result in inadvertent isolation of a pipeline. With respect to the release of radioactive material from the

nuclear system process barrier, such inadvertent valve closures are in the safe direction and do not pose any safety problems. This meets design bases 7.3.2.1.F.1 and F2.

The redundancy of trip channels for all essential variables provides a high probability that whenever an essential variable exceeds the isolation setting, the system initiates isolation. In the unlikely event that all trip channels for one essential variable in one trip system fail in such a way that a system trip does not occur, the system could still respond properly as other monitored variables exceed their isolation settings. This meets safety design basis 7.3.2.1.F.3.

The sensors, circuitry, and logic channels used in the primary containment RPV isolation control system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the isolation control system. This meets design basis 7.3.2.1.F.4.

The various power supplies used for the isolation system logic circuitry and for valve operation provide assurance that the required isolation can be effected in spite of power failures. If ac power for valves inside the primary containment is lost, dc power is available for operation of valves outside the primary containment. The MSIV control arrangement is resistant to both ac and dc power failures. Because both solenoid-operated pilot valves must be deenergized, loss of a single power supply neither causes inadvertent isolation nor prevents isolation if required.

The logic circuitry for each channel is powered from the separate sources available from the RPS buses. A loss of power here results in a single trip system trip. In no case does a loss of a single power supply prevent isolation. This meets design basis 7.3.2.1.F.6.

All instruments, valve closing mechanisms, and cables of the isolation control system can operate under the most unfavorable environmental condition associated with normal operation. The discussion of the effects of rapid nuclear system depressurization on level measurement given in section 7.2 is equally applicable to the RPV low water level transmitters used in the primary containment RPV isolation control system. The temperature, pressure, differential pressure, and level switches and transmitters, cables, and valve-closing mechanisms used were selected with ratings that make them suitable for use in the environment in which they must operate.

The special considerations made for the environmental conditions resulting from a LOCA inside the drywell are adequate to ensure operability of essential isolation components located inside the drywell.

The wall of the primary containment effectively separates adverse environmental conditions which might otherwise affect both isolation valves in a pipeline. The location of isolation valves on either side of the wall decouples the effects of environmental factors with respect to the ability to isolate any given pipeline. The previously discussed electrical isolation of control circuitry prevents failures in one part of the control system from propagating to another part. Electrical transients have no significant effect on the functioning of the RPV isolation control system. Therefore, it is concluded that design basis 7.3.2.1.F.7 is satisfied.

To ensure continued protection against the uncontrolled release of radioactive material during and after earthquake ground motions, the control system required for automatic closure of Class

A and Class B valves is seismic designed as Class I equipment as described in appendix C. This meets design basis 7.3.2.1.F.8.

The design of the MSIVs meets the requirement of design basis 7.3.2.1.G.1, in that the motive force for closing each MSIV is derived from both a source of pneumatic or gas pressure and the energy is stored in a spring. Either energy source is capable of independently closing the valve. None of the valves rely on continuity of any sort of electrical power to achieve closure in response to essential safety signals. Total loss of the power used to control the valves would result in closure. This meets design basis 7.3.2.1.G.2.

Calibration and test controls for pressure and level switches, transmitters, and trip units are located on the switches, transmitters, and trip units themselves. The switches and transmitters are located in the turbine and reactor buildings, while the trip units are located in the MCR. To gain access to the setting controls on each switch or trip unit, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected. The location of calibration and test controls in areas under the control of supervision or of the MCR operator reduces the probability that operational reliability is degraded by operator error. This meets design basis 7.3.2.1.H.1. Remote manual control of a containment isolation valve is overridden by an automatic isolation signal. Manually bypassing system logic is controlled by emergency operating procedures. These manipulations can only be performed at the direction of the plant operator. This meets design basis 7.3.2.1.H.2. Because design bases 7.3.2.1.F, G, and H were met, it can be concluded that the primary containment RPV isolation control system satisfies the reliability requirement of design basis 7.3.2.1.A.

The control system for each group A isolation valve is designed to provide closure of the valve in time to prevent uncovering of the fuel as a result of a break in the pipeline which the valve isolates. The control systems for group A and group B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline values of published regulations.

All automatic group A and group B valves and remotely operable group C valves can be closed by manipulating switches in the MCR, thus providing the operator with a means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier. This meets design basis I.

A trip of an isolation control system trip channel is annunciated in the MCR so that the operator is immediately informed of the condition. The response of isolation valves is indicated by open-closed lights. All motor-operated groups A and B isolation valves have two sets of open-closed lights. One set is located near the manual control switches which control each valve from the MCR panel. A second set is located in a separate central isolation valve position display in the MCR. The positions of air-operated isolation valves are displayed in the same manner as motor-operated valves.

Inputs to annunciators, indicators, and the computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data-logging equipment. Isolation is provided between the primary signal and the information

output. The arrangement of indications pertinent to the status and response of the primary containment reactor pressure vessel isolation control system satisfies design bases 7.3.2.1.J.1 and J.2.

The following demonstrates conformance with design basis 7.3.2.1.K. All parts of the primary containment isolation control system are testable during reactor operation. Isolation valves can be tested to ensure that they are capable of closing by operating manual switches in the MCR and observing the position lights and any associated process effects.

The trip channel and trip system responses can be functionally tested by applying test signals to each trip channel and observing the trip system response. Testing of the MSIVs is discussed in subsection 5.5.5.

Functional testing and calibration schedules developed using available failure rate data, reliability analyses, and operating experience are presented in the Technical Specifications. The schedules represent an optimization of primary containment reactor pressure vessel isolation control system reliability by considering, on one hand, the failure probabilities of individual components, and, on the other hand, the reliability effects during individual component testing on the portions of the system not undergoing tests.

IEEE 279-1971

Conformance to IEEE 279-1971 is demonstrated in topical report NEDO-10139, Paragraph 4.2. The 21 subparagraphs of 4.2 cover the 12 subparagraphs of IEEE 279-1968. The following discussion is addressed to IEEE 279-1971, subparagraphs 4.7, 4.17, and 4.22, which are different from those in IEEE 279-1968:

A. Paragraph 4.7.1: Classification of Equipment

   There is no control function in the system. It is strictly a protection system.

B. Paragraph 4.7.2: Isolation Devices

   Since there is no control function, no isolation devices are required.

C. Paragraph 4.7.3: Single Random Failure

   No single random failure of a control system can prevent proper action of the isolation system channel designed to protect against the condition.

D. Paragraph 4.7.4

   Analysis of 4.7.3 applies directly.

E. Paragraph 4.17: Manual Initiation

   Manual controls are separated in such a manner as to prevent a single failure from inhibiting an isolation. The separation of devices is maintained in both the manual

and automatic portions of the system so that no single failure in either the manual or automatic portions can prevent an isolation by either manual or automatic means. There are no areas of the system which are common to manual and automatic functions.

F. Paragraph 4.2: Identification

Panels and racks which house isolation system equipment are identified with a distinctive color marker plate listing the system and the designation of the particular redundant portion of the system. Instrument cables are identified in accordance with IEEE 279-1971.

IEEE 323-1971 and IEEE 323-1974

Compliance with the requirements of IEEE 323-1971 and IEEE 323-1974 is discussed in section 3.11.

IEEE 338-1971

The system is testable during reactor operation. The tests which may be performed cover the sensors through the final actuators, demonstrate independence of channels, and bare any credible failures while not negating any isolation.

IEEE 344-1971

Compliance with the requirements of IEEE 344-1971 is discussed in section 3.10.

Regulatory Guide 1.22 (February 1972)

The MSIVs and associated logic and sensor devices may be tested from sensor device to one of the two solenoids required for valve closure. The valve may be exercised closed with a slow acting test solenoid to verify that there are no obstructions to the valve stem at full power. A reduction in power is necessary before performing a valve closure using the two fast acting main solenoids. All the isolation valves, other than the MSIVs, may be tested from sensor to actuator during plant operation. The test may cause isolation of the process lines involved, but their isolation is tolerable.

10 CFR 50, Appendix A

A. General Design Criterion 13

The integrity of the reactor core and the reactor coolant pressure boundary (RCPB) is ensured by monitoring the appropriate plant variables and closing various isolation valves, as detailed in the various description sections.

B. General Design Criterion 20

Protection system functions. The primary containment RPV isolation control system automatically isolated the appropriate process lines.

C. General Design Criterion 21

Protection system reliability and testability. The high reliability relay and switch devices are arranged in two redundant divisions and in separate locations. Complete testing may be performed as discussed with respect to Regulatory Guide 1.22 (February 1972).

D. General Design Criterion 22

Protection system independence. Two redundant divisions are physically arranged so that no single failure can prevent an isolation. Functional diversity of sensed variables is utilized.

E. General Design Criterion 23

Fail-safe design is employed so that loss of power or postulated adverse environments leave the protection system in a safe state.

F. General Design Criterion 24

Separation of protection and control systems. The system has no control system functions. The equipment is separated from control system equipment to the extent that no single failure in a control system can prevent an isolation.

G. General Design Criterion 29

There is an extremely high probability that no anticipated operational occurrence prevents accomplishment of safety functions.

H. 10 CFR 50, Appendix B

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.3.3 (Deleted)

7.3.4 (Deleted)

7.3.5 MAIN CONTROL ROOM ENVIRONMENTAL CONTROL SYSTEM

7.3.5.1 <u>Design Bases</u>

The design bases for the MCREC system are discussed in paragraph 9.4.1.1.

7.3.5.2 <u>System Description</u>

7.3.5.2.1 Identification

The instrumentation and control for the MCR heating, ventilation, and air-conditioning (HVAC) system functions to ensure habitability of the MCR under all plant operating conditions, as described in section 6.4 and subsection 9.4.1.

The piping and instrumentation diagram for the MCR HVAC system is shown on drawing nos. H-16042 and H-26094.

7.3.5.2.2 Circuits Description

The MCRECS is a normally operating system with one or two of three air-conditioning trains in operation, as described in paragraph 6.4.1.2.1. Low-flow switches and loss-of-power relays are installed in the trains to automatically start the standby train, as required, to ensure one train will always remain in service.

A pressurization mode of operation is provided for the MCREC system for accident conditions.

In the event of a LOCA signal, refueling floor high-radiation signal, high main steam line flow signal, or MCR air intake high-radiation signal, the two redundant filter trains are automatically started, and the filter bypass dampers are closed. After verifying proper system operation, one filter train is placed on standby. The MCR air is then recirculated through the charcoal filter with sufficient outside air being drawn in through the normal intake to maintain the MCR under a positive pressure of ≥ 0.1-in. WG relative to the turbine building. Redundant differential pressure switches are provided to sense the differential pressure between the MCR and the surrounding turbine building. When the MCREC system is operating in the pressurization mode, these switches provide an alarm in the MCR if the differential pressure is lost.

7.3.5.2.3 Bypasses and Interlocks

All the isolation dampers in each MCREC system train are interlocked with the operation of the corresponding supply air and return air fans. Operation of any of these fans opens all the corresponding isolation dampers.

The redundant filter train bypass dampers are interlocked so that they close to divert flow through the charcoal filter trains when MCR pressurization is required.

7.3.5.2.4 Redundancy, Diversity, and Separation

Instrumentation and control for each MCREC system train are completely independent of each other. The channels and logic circuits are physically and electrically separated to preclude the possibility that a single event would prevent operation of the system. Electrical cables for instrumentation and control on each MCR HVAC system are routed separately.

Restroom dampers do not have redundant and independent isolation capability. However, the restroom doors, which are normally closed, act as the redundant barrier between the MCR and outside in the event the damper(s) fail to close. After initiation of the pressurization mode, the exhaust dampers are confirmed closed, and the restrooms are considered normally accessible through the doors.

Exhaust fan isolation dampers are not redundant. Thus, the exhaust fans are normally not operated, and the isolation dampers are normally closed.

7.3.5.2.5 Actuated Devices

The normal and emergency operation of each MCREC system train involves the following actuated devices:

- Recirculating air-handling unit (AHU) fans.
- Exhaust air fans (normally off).
- Electric heating coils.
- Condensing units.
- Booster fans.
- Isolation and control dampers.

7.3.5.2.6 Testability

Because the MCREC system is in use during normal plant operation, the availability of active components is evident to the plant operators, and there is no need for frequent online testing. Portions of the system normally closed to flow are periodically tested to ensure operability and integrity of the system.

7.3.5.2.7 Supporting Systems

Power supply for the MCREC system components is from separate essential ac buses that can receive standby ac power. Control power for isolation dampers, instrumentation, and controls comes from the bus that powers the corresponding equipment train.

7.3.5.2.8 Equipment Environment

Temperature, pressure, humidity, and radiation dosage are considered in selection of various equipment, instrumentation, and controls for the MCREC system. These are described in section 3.11, and subsections 9.4.1 and 6.4.1.

7.3.5.2.9 Operational Consideration

The MCR HVAC system is required during normal and abnormal plant operating conditions. The automatic circuitry is designed to start the emergency equipment as described in this section.

7.3.5.3 Analysis

7.3.5.3.1 Conformance to General Functional Requirements

The MCR HVAC system instrumentation and controls are designed to ensure the habitability of the MCR during and after all normal and abnormal plant operating conditions. The controls for the system provide warning to the operator of any abnormal operating transients in the system and automatically initiate action to pressurize the MCR, as required, to minimize the consequences of radioactive material in the environment.

Chapter 15 identifies and evaluates postulated events that can result in release of fission products due to an accident. The consequences of such an accident are described and evaluated.

Because essential variables are monitored by channels arranged for physical and electrical independence, no single failure, maintenance operation, calibration operation, or test can prevent the system from performing its function. A failure analysis of the MCREC system is presented in table 9.4-2. The MCREC system meets the requirements of IEEE 279-1971.

The sensor circuitry and logic used in the MCREC system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the MCR HVAC system.

The power supplies used for the system logic circuitry and controls ensure the required performance cannot be affected by a loss of offsite electric power or instrument air. In no case does the loss of a single power supply prevent function of the MCREC system.

All sensors and associated equipment are designed to meet Seismic Category I requirements and are protected from fire, explosion, missiles, lightning, wind, and flood to preclude functional degradation of the system performance.

7.3.6 STANDBY GAS TREATMENT SYSTEM

7.3.6.1 Design Bases

When necessary, the instrumentation and control of the SGTS are used to maintain 0.20-in. water differential pressure between inside and outside air at a rate not to exceed 4000 sf^3/min, which precludes leakage of radioactive particulates and gases directly to the environment. The SGTS is described in detail in subsection 6.2.4. The system piping and instrumentation diagram is shown on drawing no. H-26078.

7.3.6.2 System Description

7.3.6.2.1 Identification and Classification

The SGTS is an ESF required to operate in the event of certain abnormal occurrences or postulated accidents. The instrumentation and controls are designed to Class 1E standards.

7.3.6.2.2 Initiating Circuits

The system is automatically started in response to any one of the following signals:

1. High drywell pressure.
2. Low RPV water level 2.
3. High radiation in the refueling floor ventilation exhaust (paragraph 7.6.3.3).
4. High radiation in the reactor building ventilation exhaust (paragraph 7.6.3.2).
5. Manual actuation from the MCR.

7.3.6.2.3 Logic and Sequence

HNP-2 automatic initiation signal from items 1, 2, or 4, as noted in paragraph 7.3.6.2.2, would trigger simultaneously the following actions:

- Closure trip of reactor building isolation valves.

- Trip of reactor building ventilation system.
- Opening of SGTS isolation valves.
- Start of SGTS fans.

Signal from item 3 would trigger the following actions:

- Closure trip of refueling floor isolation valves.
- Trip of refueling floor ventilation system.
- Opening of SGTS isolation valves in HNP-1 and HNP-2.
- Start of SGTS fans in HNP-1 and HNP-2.

HNP-1 signal from items 1, 2, 3, or 4 would trigger the following actions:

- Closure trip of refueling floor isolation valves.
- Trip of refueling floor ventilation system.
- Opening of SGTS isolation valves.
- Start of SGTS fans in HNP-1 and HNP-2.

Individual handswitches located on the main control panel for each of the equipment trains permit manual operation.

7.3.6.2.4 Bypasses and Interlocks

The air-operated isolation valves on the discharge of the SGTS equipment train are interlocked through a relay circuit with the operation of the SGTS unit. To protect against overheating, the electric heating coil is interlocked with the SGTS fan operation, and high temperature is indicated by an alarm on the air control board. A heater "on-auto" switch is provided to enable the heater to be deactivated during SGTS filter train surveillance testing. Airflow through the SGTS is controlled by a volume damper on the exhaust fan, and flow is recorded on the main control panel. Low flow on the operating filter train initiates an alarm to alert the operator to start the redundant equipment train. If the bed temperature exceeds 290°F, the heat detection system notifies the control room. To extinguish a fire in the charcoal bed, a manually activated deluge system sprays the charcoal filters with water.

Upon receipt of an initiation signal due to high radiation, the reactor building or ventilation isolation valves close and remain closed unless a manual reset switch is activated (and the radiation signal no longer exists).

7.3.6.2.5 Redundancy, Diversity, and Separation

Each SGTS unit is automatically initiated by independent control systems. The channels and logic circuits are physically and electrically separated to preclude the possibility that a single event would prevent operation of the SGTS. Electrical cables for instrumentation and control on each SGTS equipment train are routed separately.

7.3.6.2.6 Actuated Devices

Initiation of the SGTS includes starting the SGTS exhaust fan, energizing electric heating for preheating the air in maintaining the relative humidity below 70%, and opening valves on the inlet and outlet sides of the SGTS equipment train.

7.3.6.2.7 Testability

Control and logic circuitry used in the controls for the SGTS can be individually checked by applying tests or calibration signals to the sensors and observing trip or control responses. Operation of the isolation valves and fans from manual switches verifies the ability of breakers and damper mechanisms to operate.

7.3.6.2.8 Supporting Systems

Each SGTS equipment train has an SGTS fan, electric heating coil, and associated air-operated isolation valves which require power. Power supply for various components of each SGTS equipment train is from separate essential 600-V-ac buses which can receive standby ac power. Control power for the SGTS isolation valves and the controls comes from the buses that power the corresponding equipment train. These valves are operated by air cylinders with an uninterruptible air and are controlled by solenoid valves for each isolation damper. If either control gas or electric control power is lost, the isolation dampers are operated by springs mounted on the damper.

7.3.6.2.9 Environmental Considerations

Temperature, pressure, humidity, and radiation dosage are considered in the selection of the various equipment, instrumentation, and controls for the SGTS described in section 3.11 and subsection 6.2.4.

7.3.6.2.10 Operational Considerations

During normal plant operating conditions, the SGTS is required only when it is being tested.

7.3.6.3 Analysis

7.3.6.3.1 Conformance to General Functional Requirements

The SGTS is designed to initiate action which provides timely protection against the consequences of release of radioactive materials inside the secondary containment following any accident. Chapter 15 identifies and evaluates postulated events that can result in release of fission products due to an accident.

Because essential variables are monitored by channels arranged for physical and electrical independence and because a dual-trip-system arrangement is used to initiate the SGTS, no single failure, maintenance operation, calibration operation, or test can prevent the system from operating when required. The sensor circuitry and logics used in the SGTS are not used in the control of any process system. Thus, malfunction and failure in the controls of process systems have no direct effect on the SGTS.

The various motive power supplies used for the SGTS logic circuitry and controls provide assurance that the required initiation can be effected in spite of loss of electric power or loss of instrument air. In no case does a loss of a single power supply prevent initiation of the SGTS when required. All instruments, isolation valve closing mechanisms, and cables of the SGTS can operate under the worst environmental conditions associated with post-accident operation. All active components of SGTS instrumentation and control can be tested and calibrated during plant operation.

All sensors and associated equipment are designed to meet Seismic Category 1 requirements and are protected from fire, explosion, missiles, lightning, wind, and flood to preclude functional degradation of system performance.

Reactor building and refueling floor normal ventilation supply and exhaust air ducts isolation dampers are designed to fail closed.

Inputs to annunciators and indicators are arranged so that no malfunction of the annunciating and indicating device can functionally disable the system. Direct signals from the SGTS sensors are not used as inputs to annunciating or data-logging equipment. Isolation is provided between the primary signals and the information output.

All controls for interrupting any part of the system operation are located in the MCR or at a control station accessible if conditions require use of the SGTS. Any controls locally located have locks to prevent unauthorized operation.

All electrical instrumentation and controls essential to operation of the SGTS meet IEEE 279-1971 criteria.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

TABLE 7.3-1

HPCI SYSTEM INSTRUMENT SPECIFICATIONS

HPCI Function	Instrument	Trip/Setting	Range
RPV water level - high (level 8)[(b)]	Differential pressure transmitter/trip unit	(a)	0 - 60 in.
Turbine exhaust pressure high	Pressure transmitter/trip unit	≤ 146 psig	0 - 250 psig
HPCI system pump suction pressure - low	Pressure transmitter/trip unit	≤ 12.6 in. Hg vacuum	30 in. Hg vacuum/
RPV water level - low, low, (level 2)[(b) (e)]	Differential pressure transmitter/trip unit	(a)	-150/0/+60 in.
Drywell pressure - high[(e)]	Pressure transmitter/trip unit	(a)	0 - 5 psig
HPCI steam supply line pressure - low	Pressure transmitter/trip unit	(a)	0 - 1200 psig
CST level - low[(d)]	Level switch/trip unit	(a)	-2 in./0/+2 in. H_2O
Turbine overspeed	Centrifugal device	≤ 5000 rpm	
Suppression pool water level - high[(c)]	Differential pressure transmitter/trip unit	(a)	121 - 221 in. H_2O
HPCI turbine steam line flow - high	Differential pressure transmitter/trip unit	(a)	
HPCI pump discharge flow - low	Differential pressure transmitter/trip unit	(a)	

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero, see figure 5.4-2.
c. Referenced to suppression pool invert.
d. Referenced to CST bottom.
e. Incident detection circuitry instrumentation.

TABLE 7.3-2

ADS INSTRUMENT TRIP SETTINGS

ADS Function	Instrument	Trip Setting	Range
RPV water level - low(level 3)[b] [c]	Level transmitter/trip unit	(a)	0 - 60 in.
RPV water level - low low low, (level 1) [b] [c]	Level transmitter/trip unit	(a)	-150/0/+60 in.
Primary containment (drywell) pressure - high[c]	Pressure transmitter/trip unit	(a)	0 - 5 psig
ADS time delay[c]	Timer	(a)	0 - 180 s
LPCI pump discharge pressure - high[c]	Pressure transmitter/trip unit	(a)	0 - 500 psig
CS pump discharge pressure - high[c]	Pressure transmitter/trip unit	(a)	0 - 500 psig
ADS drywell pressure bypass time delay	Timer		1 - 30 min

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero, see figure 5.4-2.
c. Incident detection circuitry instrumentation.

TABLE 7.3-3

CORE SPRAY SYSTEM INSTRUMENT SPECIFICATIONS

Core Spray Function	Instrument	Trip Setting	Range
RPV water level - low low low, (level 1)[(b) (c)]	Differential pressure transmitter/ trip unit	(a)	-150/0/+60 in.
Primary containment pressure - high[(c)]	Pressure transmitter/trip unit	(a)	0 - 5 psig
RPV pressure - low (injection permissive)	Pressure transmitter/trip unit	(a)	0 - 1500 psig
CS pump discharge flow - low (bypass)	Differential pressure transmitter/ trip unit	(a)	0 - 50 in. H_2O
CS sparger differential pressure - high	Differential pressure switch	≤ 3.1 psid[(d)]	0 - 25 psid
Pump discharge flow	MCR flow indication	--	0 - 7000 gal/min
Pump suction pressure	Pressure indicator	--	-30 in. Hg to 150 psig
Pump discharge pressure	Pressure indicator	--	0 - 500 psig

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero, see figure 5.4-2.
c. Incident detection circuitry instrumentation.
d. The trip setting is ≤ 3.1 psid greater (less negative) than the normal indicated ΔP at rated core power and flow.

TABLE 7.3-4

LPCI INSTRUMENT SPECIFICATIONS

LPCI Function	Instrument	Trip Setting	Range
RPV water level - low low low (level 1) (LPCI pump start signal)[(b) (c)]	Differential pressure transmitter/ trip unit	(a)	-150/0/+60 in.
Primary containment (drywell) pressure - high (LPCI initiation)[(c)]	Pressure transmitter/trip unit	(a)	0 - 5 psig
RPV shroud level (level 0) [(b)]	Differential pressure transmitter/ trip unit	(a)	-317 to -17 in.
LPCI RPV pressure - low (recirculation discharge valve)	Pressure transmitter/trip unit	(a)	0 - 1500 psig
LPCI RPV pressure - low (LPCI injection valve)	Pressure transmitter/trip unit	(a)	0 - 1500 psig
LPCI pump flow - low (bypass)	Differential pressure transmitter/ trip unit	(a)	0 - 50 in.

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero, see figure 5.4-2.
c. Incident detection circuitry instrumentation.

TABLE 7.3-5

HPCI SYSTEM
MINIMUM NO. OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument	No. of Trip Channels Provided	Minimum No. of Trip Channels Required to Maintain Functional Performance
HPCI system initiation	RPV low water level (level 2)	Level transmitter/trip unit	2 per trip system	2 per untripped trip system
HPCI system initiation	Primary containment high pressure	Pressure transmitter/ trip unit	2 per trip system	2 per untripped trip system
HPCI system turbine	HPCI system pump discharge flow	Flow indicator controller	1	1
HPCI system turbine	RPV high water level (level 8)	Level transmitter/trip unit	2	2
HPCI system turbine	Turbine exhaust high pressure	Pressure transmitter/ trip unit	2	1[a]
HPCI system turbine	HPCI system pump low suction pressure	Pressure transmitter/ trip unit	1	1
Minimum-flow bypass valve	HPCI system pump flow	Flow transmitter/trip unit	1	1
HPCI system steam supply valve and suppression chamber suction valve	HPCI system steam supply low pressure	Pressure transmitter/ trip unit	2 per trip system	2 per untripped trip system
Suppression chamber suction valve and CST suction valve	CST low level and suppression pool high level	Level switch	2	2[b]

a. An inoperable trip channel is placed in the untripped state.
b. If either channel is inoperable, suction path must be aligned to suppression pool.

TABLE 7.3-6

ADS
MINIMUM NO. OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Initiating Function	Instrument	No. of Trip Channels Provided	Minimum No. of Trip Channels Required to Maintain Functional Performance[a]
RPV low water level (level 1)	Level transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
RPV low water level (level 3)	Level transmitter/trip unit	2 (1 per trip system)	1 per untripped trip system
Primary containment high pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
Time delay	Timer	2 (1 per trip system)	1 per untripped trip system
AC interlock (RHR or CS pump running)	Pressure transmitter/trip unit	4 per trip system	2 per untripped trip system
ADS drywell pressure bypass time delay	Timer	4 (2 per trip system)	2 per untripped trip system

a. One trip logic of each trip system must be fully operable. Both an RPV low water level trip channel and a primary containment high-pressure trip channel should not be inoperable in any one trip logic.

TABLE 7.3-7

CORE SPRAY SYSTEM
MINIMUM NO. OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument	No. of Trip Channels Provided	Minimum No. of Trip Channels Required to Maintain Functional Performance
CS system	RPV low water level (level 1)	Level transmitter/trip unit	4 (2 per trip system)	2 per untripped trip unit
CS system	Primary containment	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip unit
CS discharge valves	RPV low pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
CS sparger leak detection	Core pressure differential	Differential pressure switch	1 per sparger (alarm only)	1 per sparger (alarm only)

TABLE 7.3-8

LPCI
MINIMUM NO. OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument	No. of Trip Channels Provided	Minimum No. of Trip Channels Required to Maintain Functional Performance
LPCI initiation	RPV low water level (level 1)	Level transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
LPCI initiation	Primary containment high pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
Containment spray valves	RPV low water level inside shroud (level 0)	Level transmitter/trip unit	2	1[a]
Minimum flow bypass valves	LPCI pumps discharge low flow	Differential pressure transmitter/trip unit	4 (1 per pump)	4
LPCI injection valves	RPV low pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
Reactor recirculation discharge valves	RPV low pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system
Containment cooling valves	Primary containment (drywell) high pressure	Pressure transmitter/trip unit	4 (2 per trip system)	2 per untripped trip system

a. An inoperable sensor is placed in the untripped state.

TABLE 7.3-9 (SHEET 1 OF 3)

PRIMARY CONTAINMENT AND RPV ISOLATION CONTROL SYSTEM ISOLATION SETPOINTS

Isolation Function	Sensor	Trip Settings
RPV water level - low (level 3)[c]	Differential pressure transmitter/trip unit	(a)
RPV water level - low low low (level 1)[c]	Differential pressure transmitter/trip unit	(a)
Main steam line radiation - high	Radiation monitor	≤ 3 x background
Main steam line flow - high	Differential pressure transmitter/trip unit	(a)
Main steam line pressure - low	Pressure switch	(a)
Drywell pressure - high	Pressure transmitter/ trip unit	(a)
RCIC equipment room ambient temperature - high	RTD/trip unit	(a)
RCIC turbine steam line pressure - low	Pressure transmitter/ trip unit	(a)
HPCI equipment room ambient temperature - high	RTD/trip unit	(a)
HPCI turbine steam line pressure - low	Pressure transmitter/ trip unit	(a)
Reactor building ventilation exhaust radiation - high	Radiation monitor	(a)
Refueling floor ventilation exhaust radiation - high	Radiation monitor	(a)
RWC equipment room ambient temperature - high	RTD/trip unit	(a)
Main steam line tunnel temperature - high	RTD/trip unit	(a)

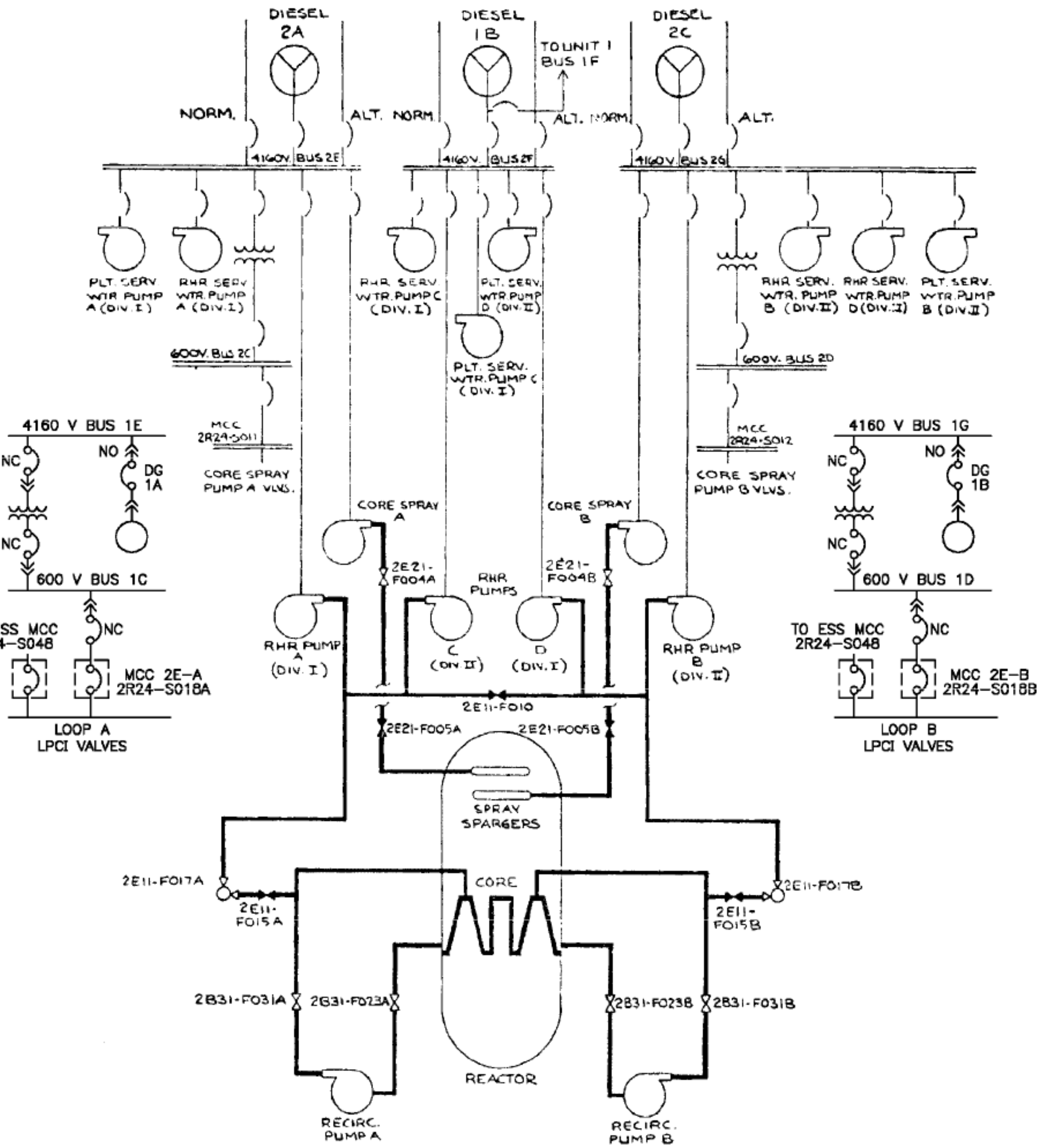
TABLE 7.3-9 (SHEET 2 OF 3)

Isolation Function	Sensor	Trip Setting
RWC differential flow - high	Differential flow switch	79 gal/min
Reactor pressure - high (shutdown cooling mode)	Pressure transmitter/ trip unit	(a)
RWC equipment room vent air in/out differential temperature - high	Differential temperature trip units (RTDs)	(a)
Main turbine condenser vacuum - low	Pressure switch	(a)
RCIC turbine exhaust diaphragm pressure - high	Pressure transmitter/ trip unit	(a)
HPCI turbine exhaust diaphragm pressure - high	Pressure transmitter/ trip unit	(a)
RCIC turbine steam line flow - high	Differential pressure transmitter/trip unit	(a)
RCIC turbine steam line instrument failure	Differential pressure transmitter/trip unit	-100 in. H_2O[d]
HPCI turbine steam line flow - high	Differential pressure transmitter/trip unit	(a)
HPCI turbine steam line instrument failure	Differential pressure transmitter/trip unit	-100 in. H_2O[d]
RPV water level - low low (level 2)[c]	Differential pressure transmitter/trip unit	(a)
RCIC suppression pool area ambient temperature - high	RTD/trip unit	(a)
RCIC suppression pool area vent air in/out differential temperature - high[b]	Differential temperature trip unit (RTDs)	(a)
Drywell radiation - high	Radiation monitor	(a)

TABLE 7.3-9 (SHEET 3 OF 3)

Isolation Function	Sensor	Trip Setting
RCIC suppression pool area ambient temperature - time delay relays	Timer	(a)
HPCI pipe penetration room temperature - high	RTD/trip unit	(a)
HPCI suppression pool area ambient temperature - high	RTD/trip unit	(a)
HPCI suppression pool area ventilation air in/out differential temperature - high	Differential temperature/ trip unit (RTD)	(a)
HPCI suppression pool area ambient temperature - time delay relays	Timer	(a)
Turbine building area temperature - high	Temperature switch	(a)

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Final values for these setpoints were established as result of data obtained during the startup and power test program.
c. Referenced to instrument zero; see figure 5.4-2.
d. The value listed is actual trip setpoint; see HNP-2 Instrument Setpoint Index.



ACAD 2070301

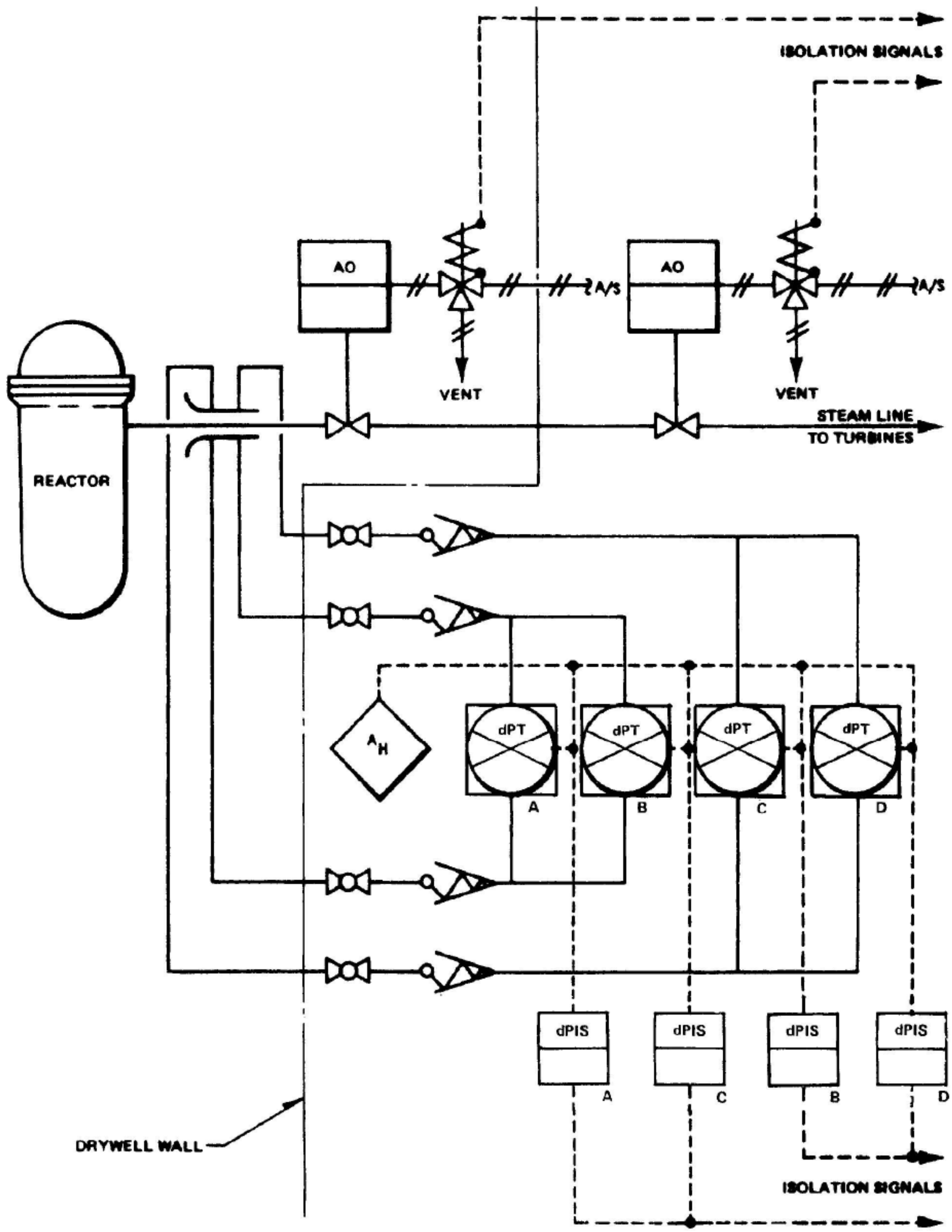
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ECCS POWER DISTRIBUTION

FIGURE 7.3-1



ACAD 2070302

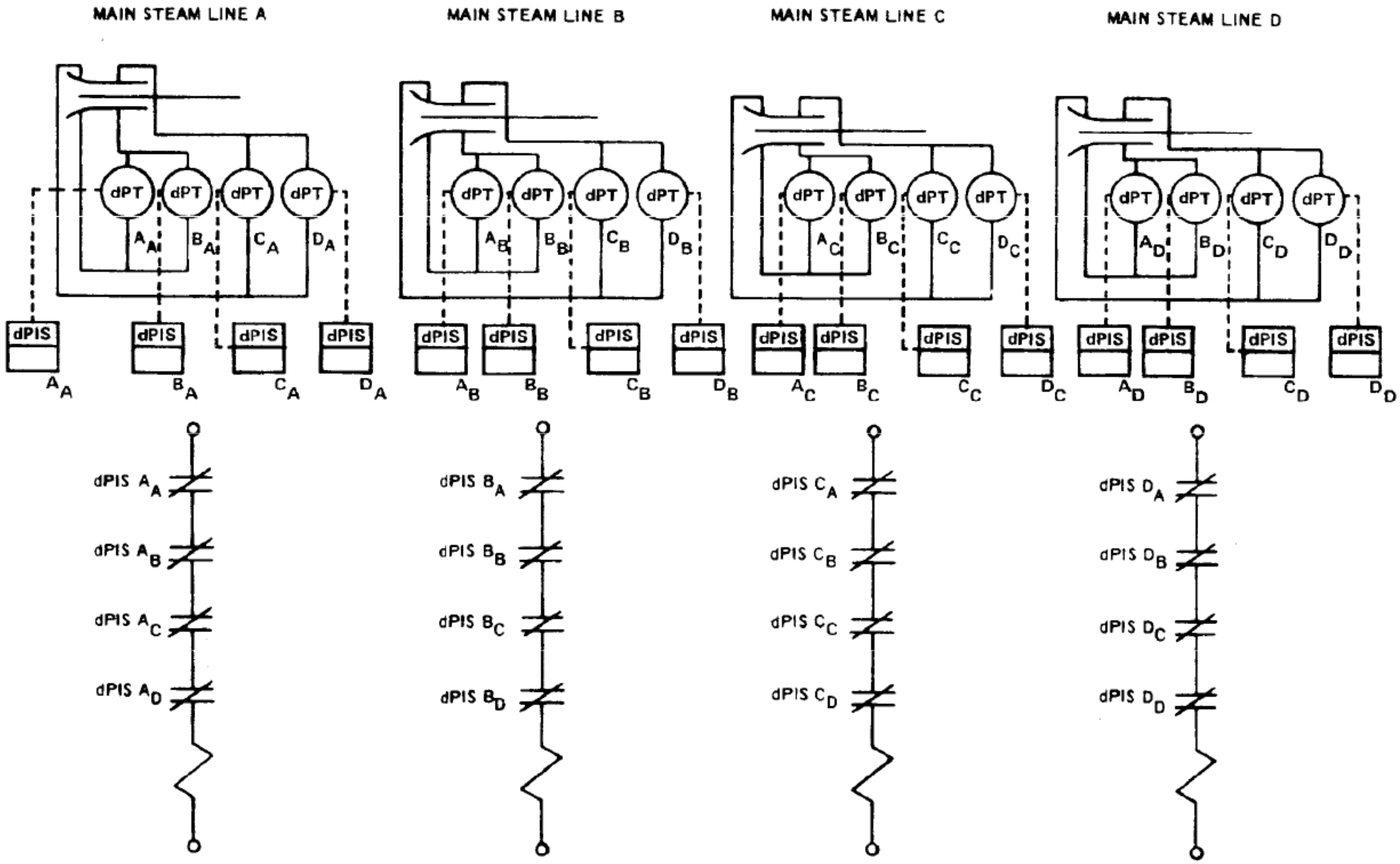
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL ARRANGEMENT FOR
MAIN STEAM LINE BREAK DETECTION BY
FLOW MEASUREMENT

FIGURE 7.3-2



ACAD 2070303

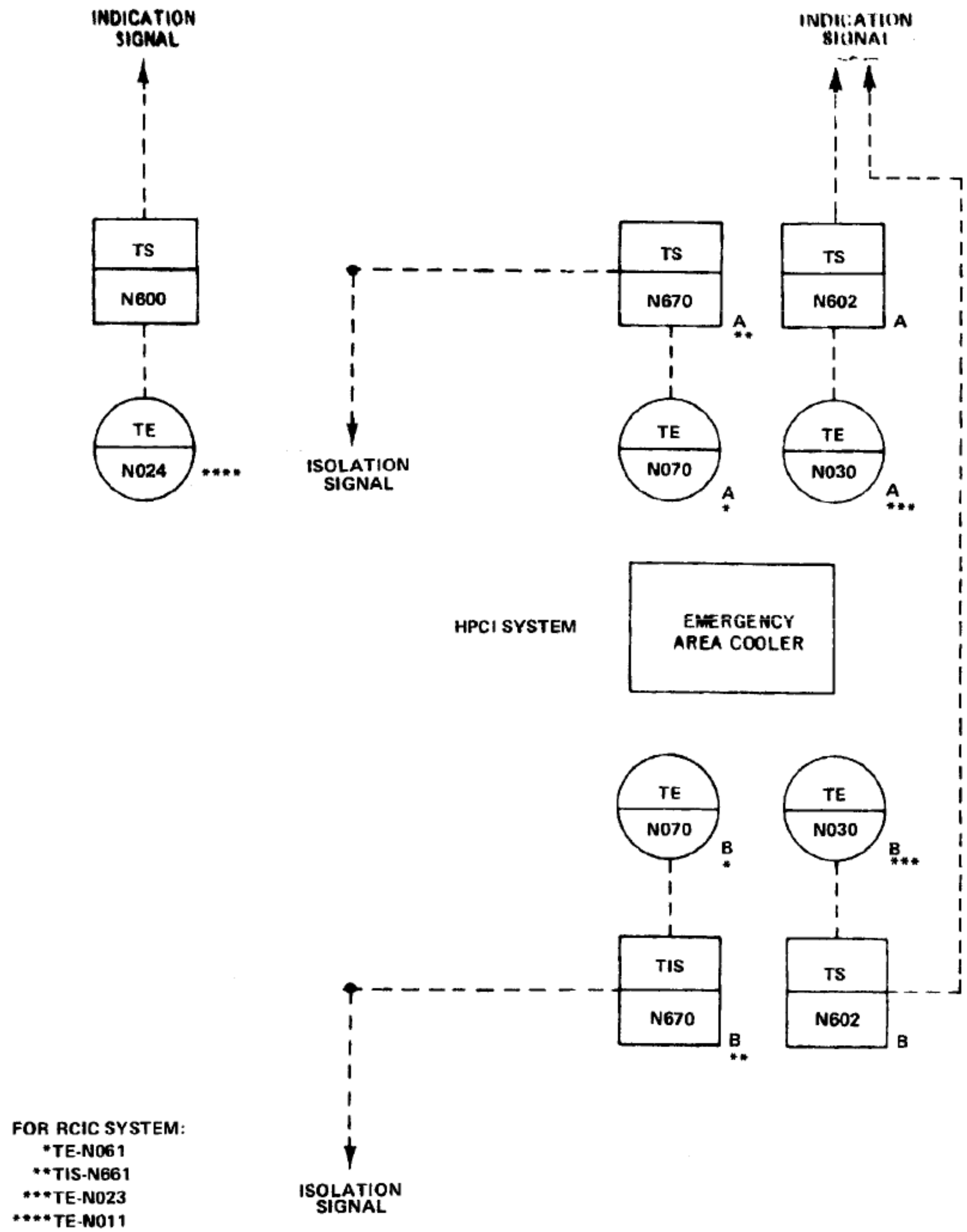
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MAIN STEAM LINE HIGH FLOW CHANNEL SCHEMATIC

FIGURE 7.3-3



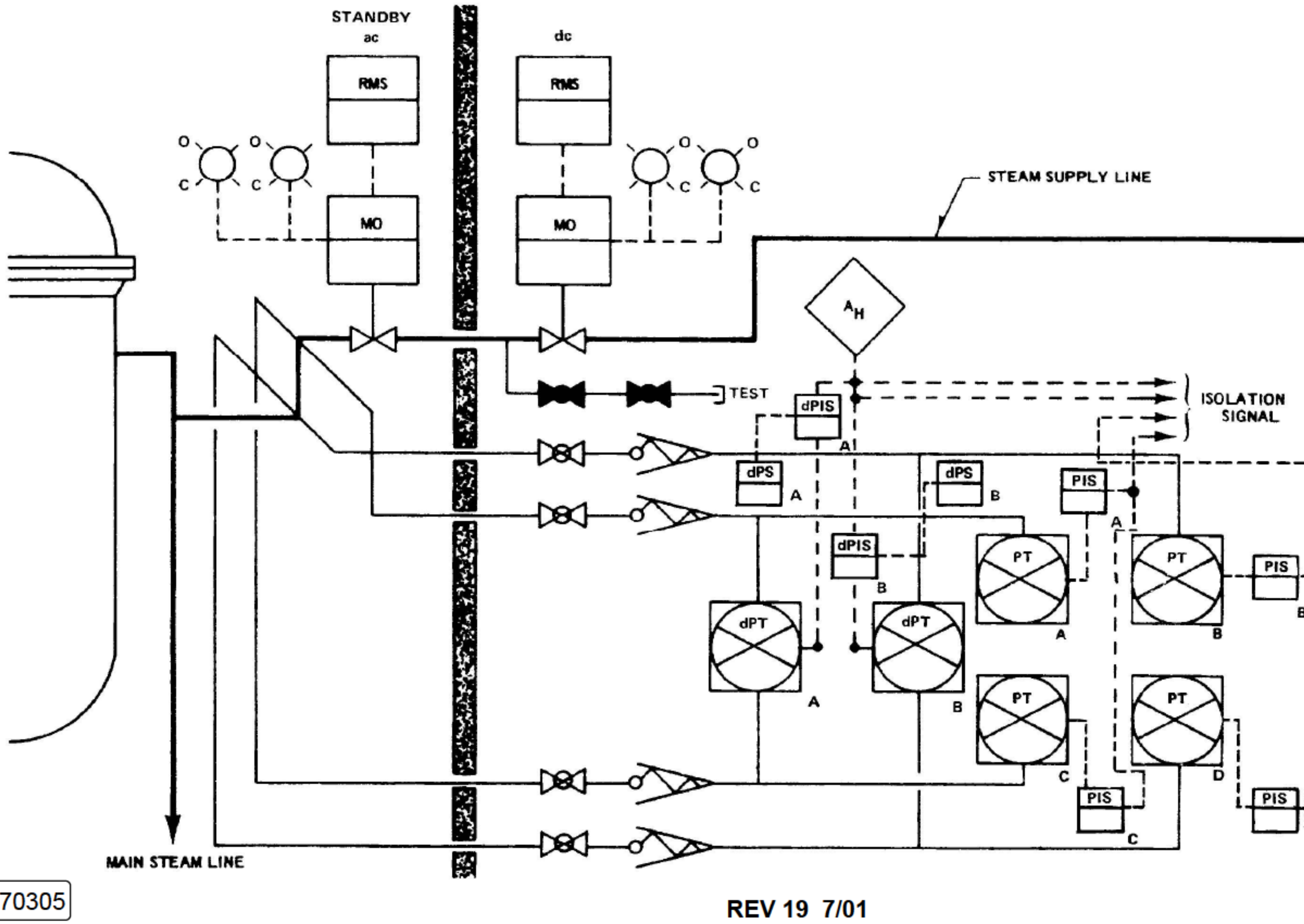
ACAD 2070304

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ROOM TEMPERATURE DETECTOR ARRANGEMENT (HPCI/RCIC)

FIGURE 7.3-4



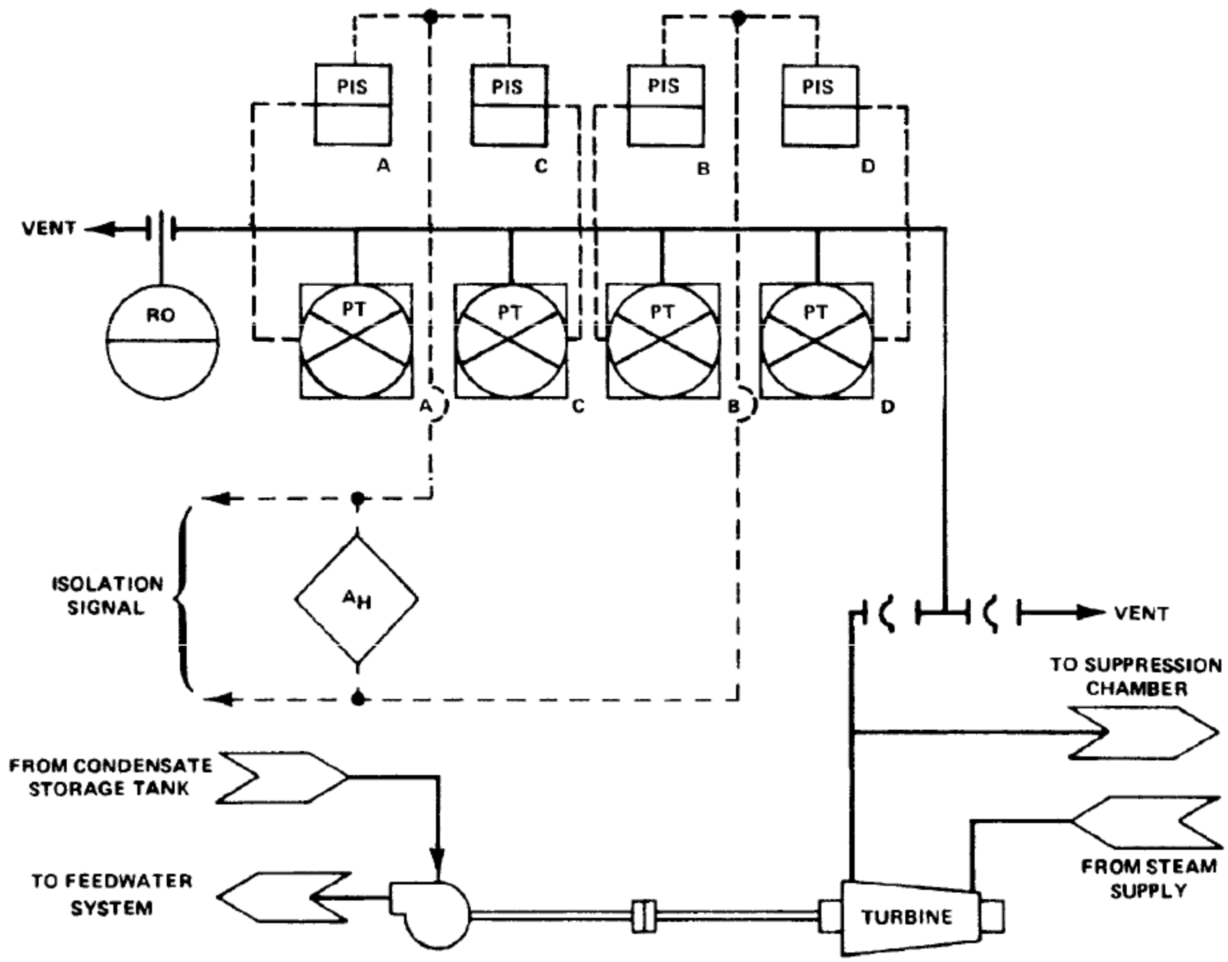
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL ELBOW FLOW-SENSING ARRANGEMENT

FIGURE 7.3-5



ACAD 2070306

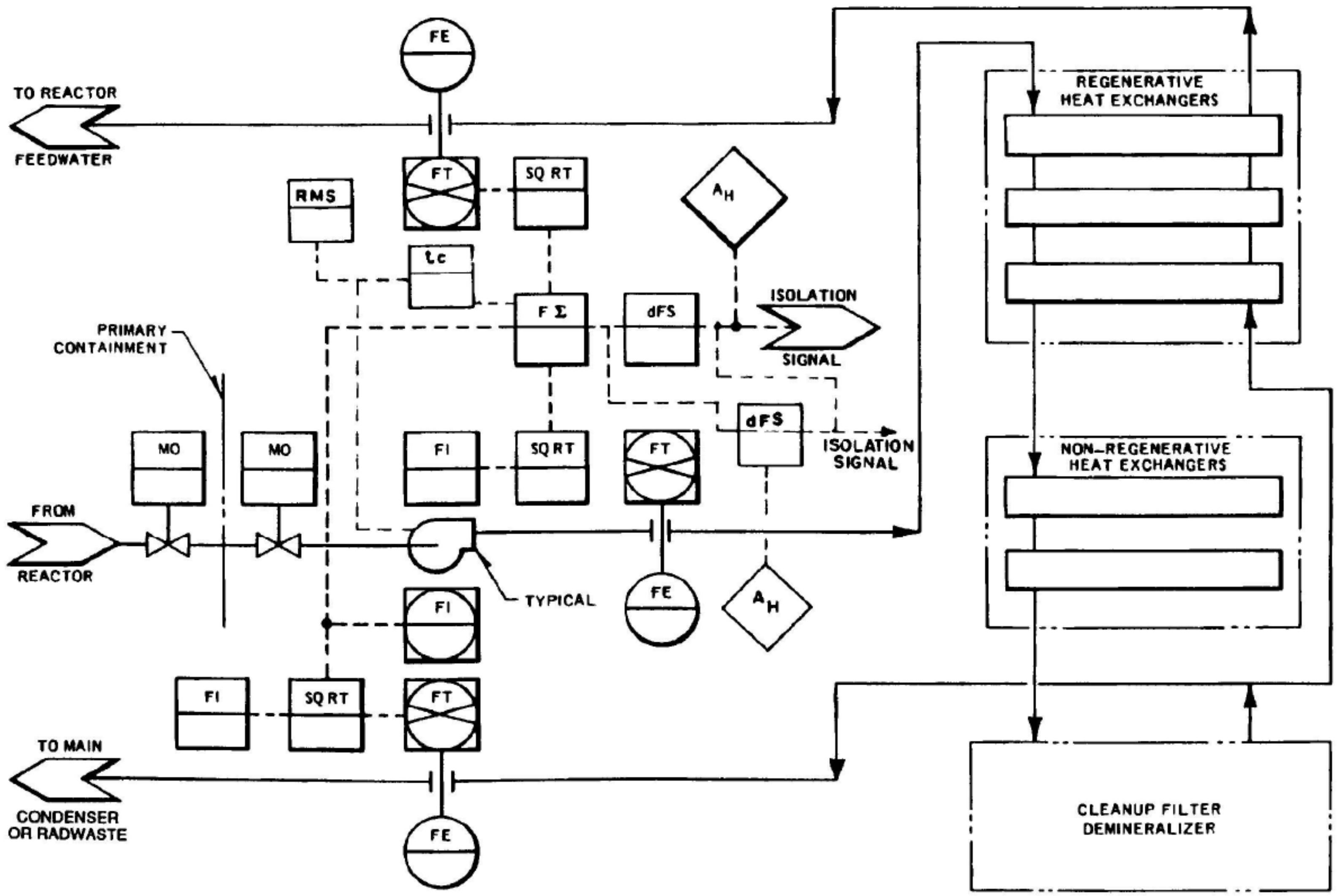
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL HIGH EXHAUST DIAPHRAGM PRESSURE DETECTION ARRANGEMENT (HPCI/RCIC)

FIGURE 7.3-6



ACAD 2070307

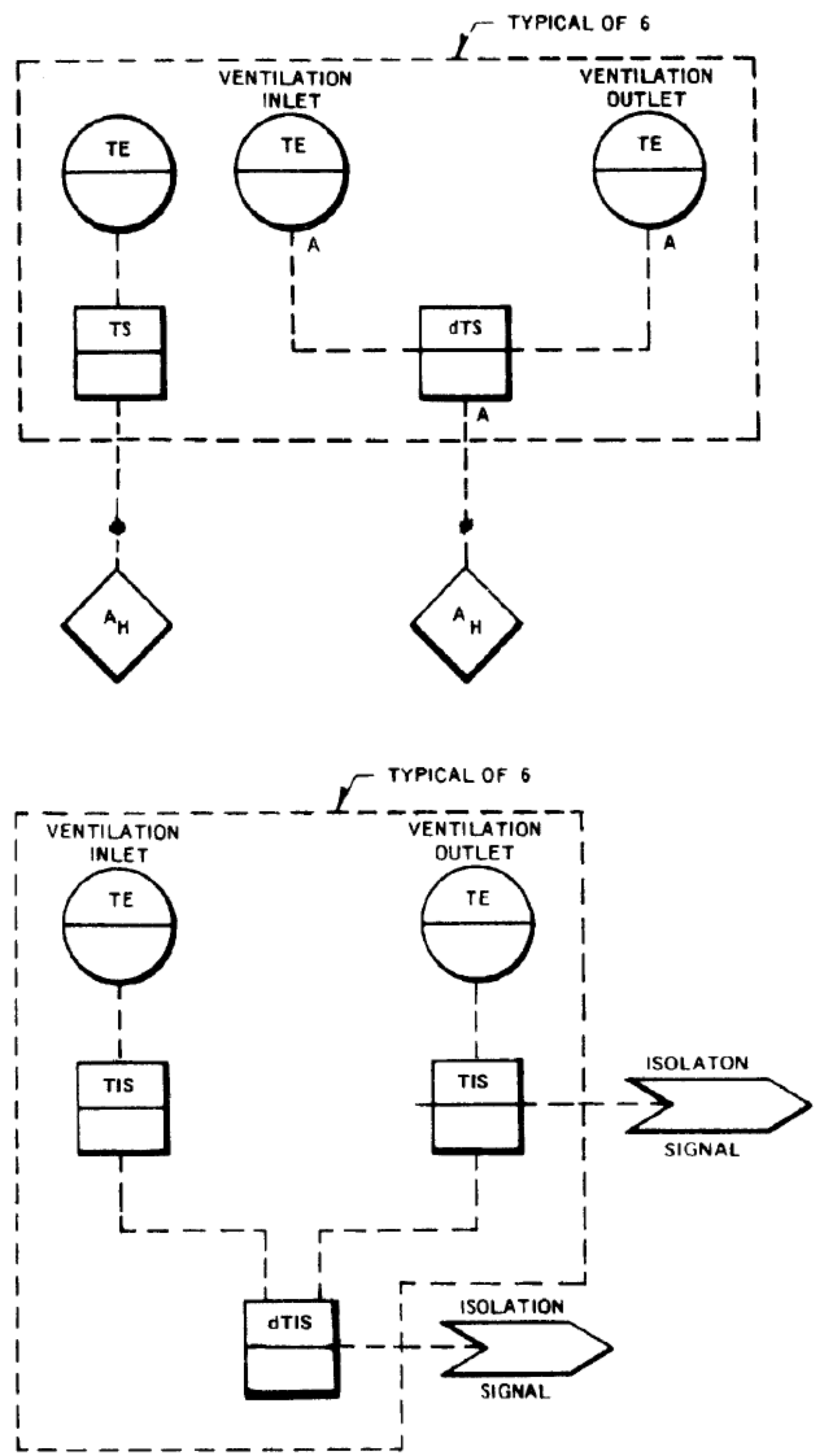
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RWC BREAK DETECTION BY DIFFERENTIAL FLOW MEASUREMENT

FIGURE 7.3-7



ACAD 2070308

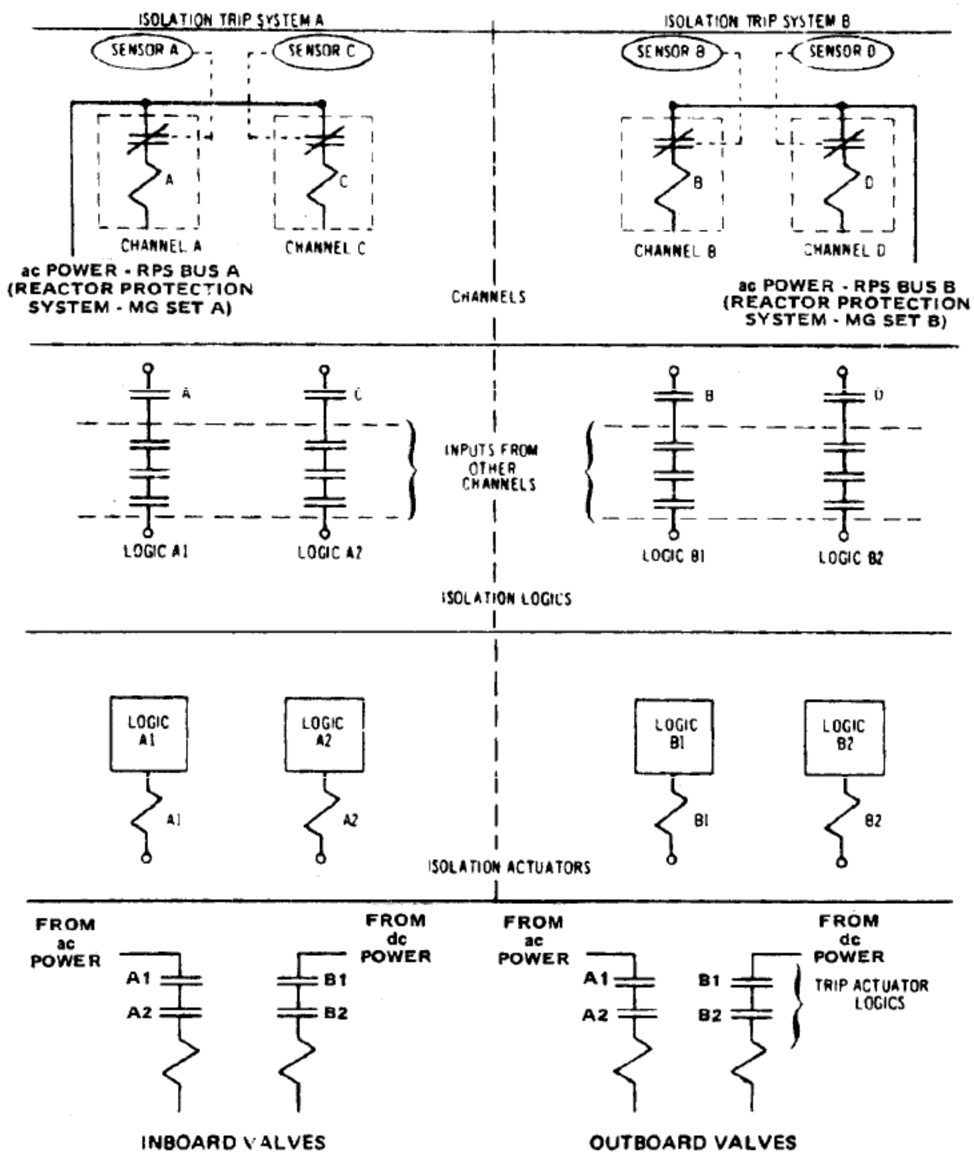
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HIGH AMBIENT AND HIGH DIFFERENTIAL TEMPERATURE MEASUREMENT (RWC)

FIGURE 7.3-8



REFERENCE DWGS:
H-27450 REV 16
H-27454 REV 14
H-27455 REV 12
H-27456 REV 13
H-27460 REV 11
H-27461 REV 11

ACAD 2070309

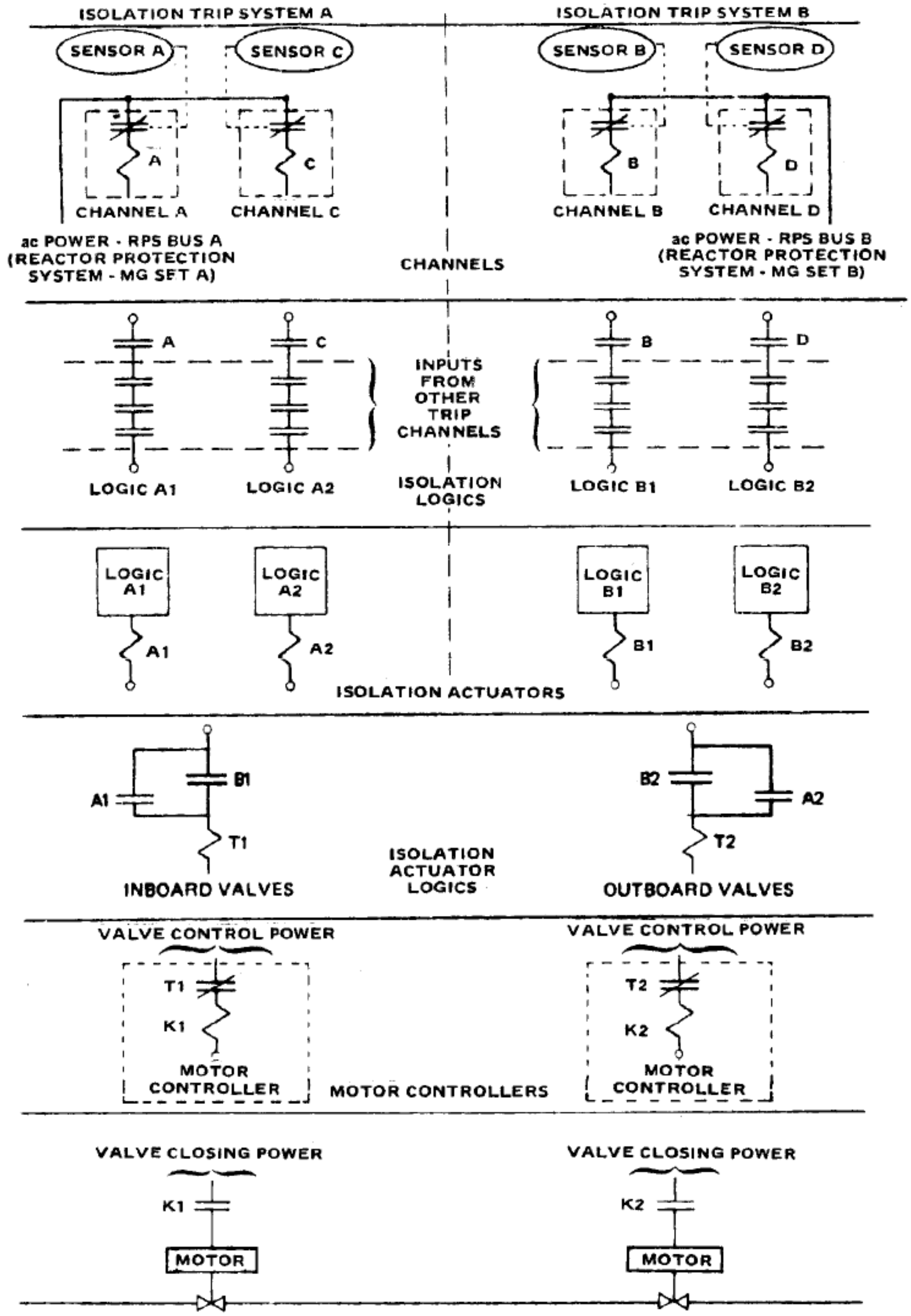
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MSIV TYPICAL ISOLATION CONTROL

FIGURE 7.3-9



REF DWG H-27450 REV 16
REF DWG H-27454 REV 14
REF DWG H-27455 REV 12
REF DWG H-27456 REV 13
REF DWG H-27460 REV 11
REF DWG H-27461 REV 11

ACAD 2070310

REV 19 7/01

SOUTHERN COMPANY Energy to Serve Your World®

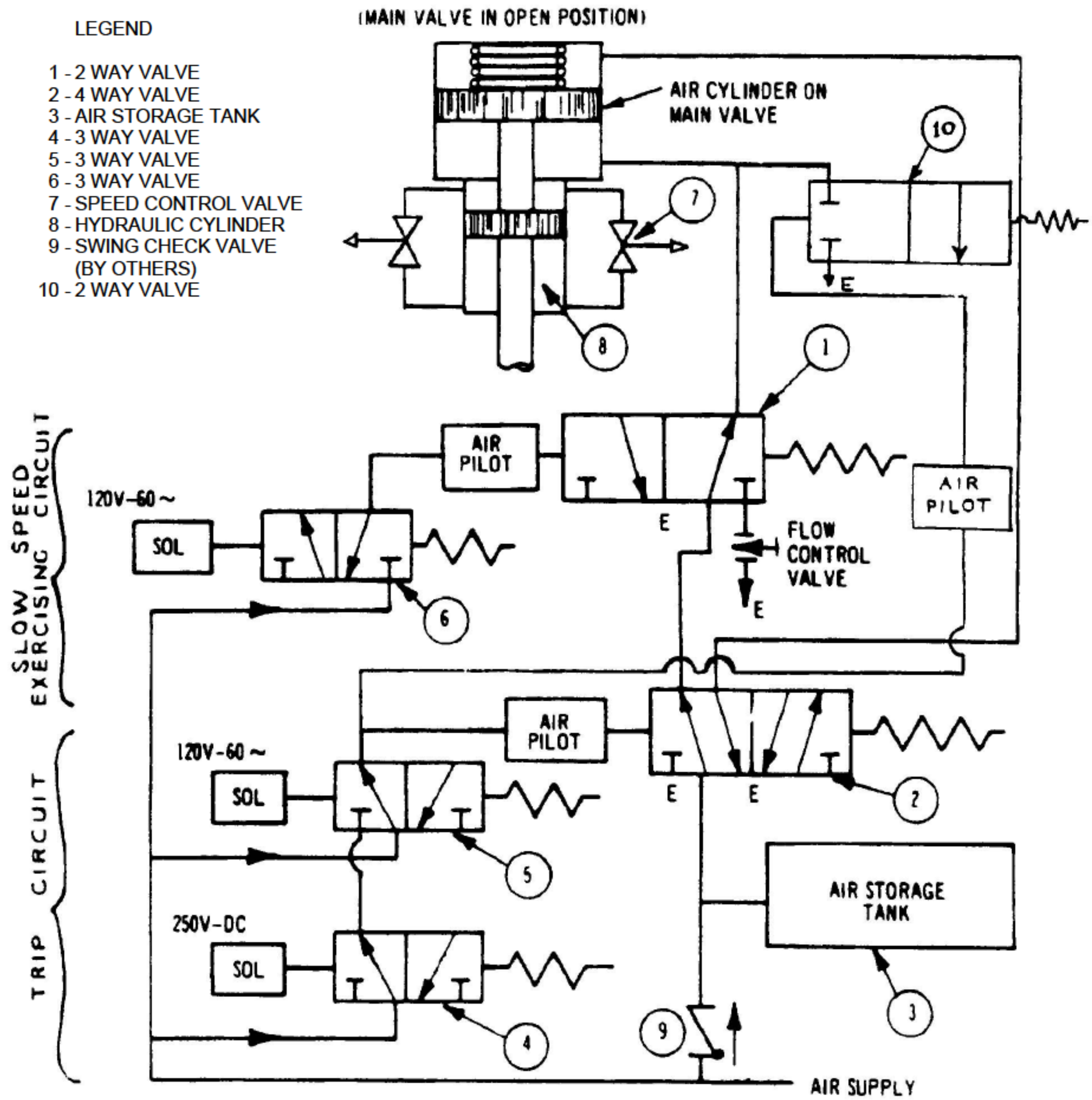
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MOV TYPICAL ISOLATION CONTROL

FIGURE 7.3-10

LEGEND

1 - 2 WAY VALVE
2 - 4 WAY VALVE
3 - AIR STORAGE TANK
4 - 3 WAY VALVE
5 - 3 WAY VALVE
6 - 3 WAY VALVE
7 - SPEED CONTROL VALVE
8 - HYDRAULIC CYLINDER
9 - SWING CHECK VALVE
(BY OTHERS)
10 - 2 WAY VALVE



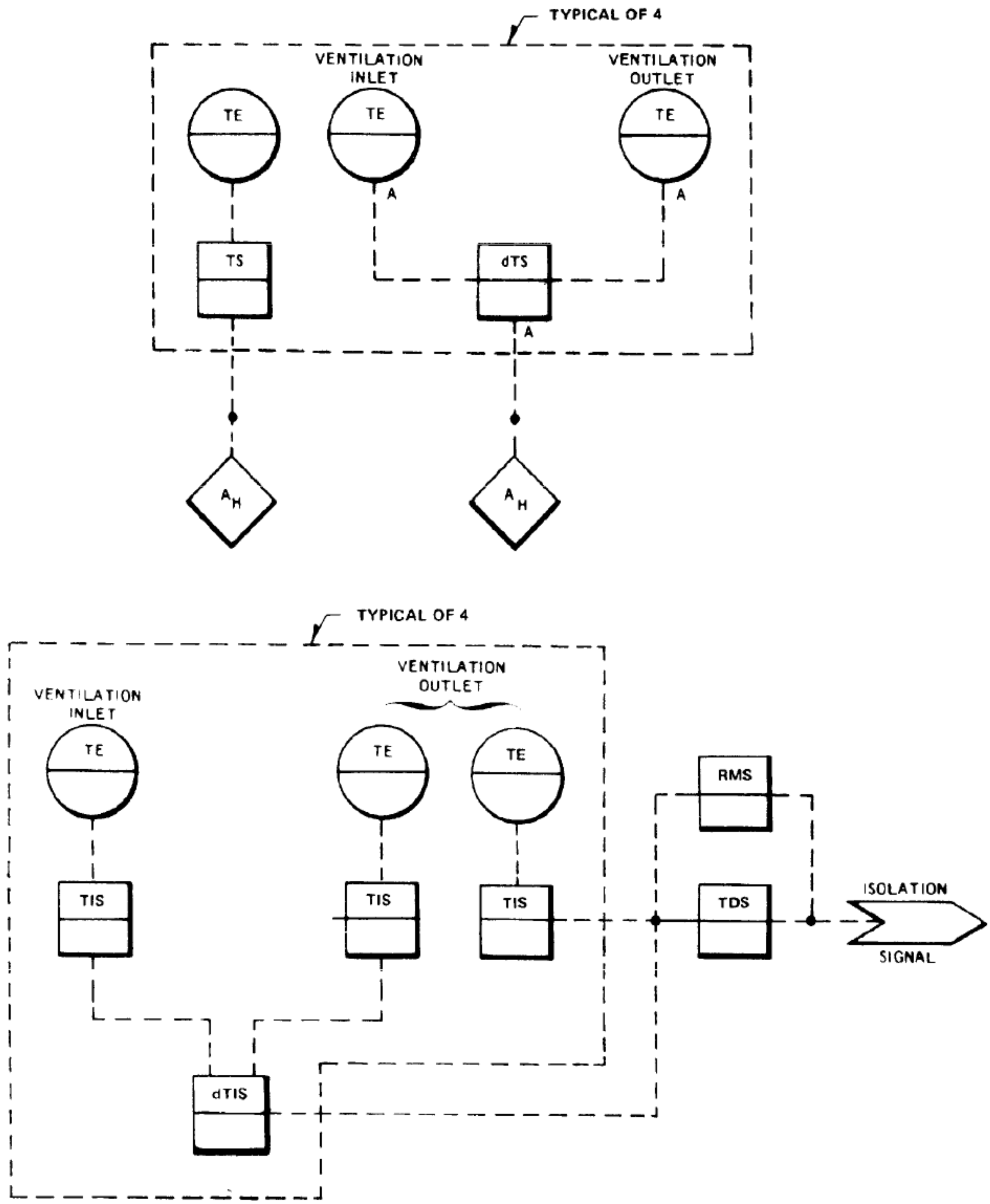
ACAD 2070311

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

MSIV SCHEMATIC CONTROL DIAGRAM

FIGURE 7.3-11



ACAD 2070312

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

HIGH AMBIENT AND HIGH DIFFERENTIAL TEMPERATURE MEASUREMENT (SUPPRESSION POOL)

FIGURE 7.3-12

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

7.4.1 REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

The RCIC system provides core cooling during reactor shutdown by pumping makeup water into the reactor pressure vessel (RPV) upon loss of the reactor feedwater system.

7.4.1.1 Design Bases

The RCIC system is designed:

- To be capable of maintaining sufficient coolant in the RPV in case of a loss of main feedwater flow.
- To provide for automatic and remote-manual operation of the system.
- To receive power from the essential power systems to provide a high degree of assurance that the system operates when necessary.
- For periodic testing performance during reactor operation to provide a high degree of assurance that the system operates when necessary.

The RCIC system is considered a safety system rather than an emergency core cooling system (ECCS) because it may be called on to operate during safe shutdown which does not require ECCS actuation; e.g., station blackout (station blackout is discussed in section 8.4). The system is designed to meet the requirements (with exceptions as described in paragraph 7.4.1.3) of Institute of Electrical and Electronics Engineers (IEEE) 279-1971, IEEE 323-1971, IEEE 338-1971, and IEEE 344-1971; General Design Criteria 13, 20-22, 29, and 37 of 10 CFR 50, Appendix A; and Regulatory Guide 1.22.

7.4.1.2 System Description

7.4.1.2.1 Identification and Classification

The RCIC system provides core cooling during reactor shutdown by pumping makeup water into the RPV upon a loss of flow from the main feed system. It is activated in time to preclude conditions which lead to inadequate core cooling.

7.4.1.2.2 Power Sources

The RCIC pump is turbine driven, and the RCIC trip system is fed from the 125/250-V-dc buses.

7.4.1.2.3 Equipment Design

When actuated, the RCIC system pumps water from either the condensate storage tank (CST) or the suppression chamber to the RPV via the feedwater lines. The RCIC system includes one turbine-driven pump, one barometric condenser dc vacuum pump, one vacuum dc condensate pump, automatic valves, control devices for this equipment, sensors, and logic circuitry. The arrangement of equipment and control devices is shown on drawing nos. H-26023 and H-26024.

Pressure and level switches and transmitters used in the RCIC system are located on racks in the reactor building. The only operating component of the RCIC system that is located inside the primary containment is one of the two RCIC system turbine steam supply isolation valves.

The rest of the RCIC system instrumentation and control components are located outside the primary containment. Cables connect the sensors to trip units and other control circuitry in the main control room (MCR). Although the system is designed to allow a full-flow functional test of the system during normal reactor power operation, the test controls are arranged so that the system can operate automatically to fulfill its safety function regardless of which test is being conducted.

7.4.1.2.3.1 **Initiating Circuits**. RPV water level 2 is monitored by four level transmitters, and RPV level 8 is monitored by two level transmitters which sense the difference between the pressure to a constant reference leg of water and the pressure resulting from the actual height of water in the vessel. Cables are routed from the transmitters to trip units located in the MCR. Two pipelines, attached to taps above and below the water level on the reactor vessel, are required for each of the two reference legs used with the RCIC. The pipelines are physically separated from each other and tap off the reactor vessel at widely separated points. Two pairs of differential pressure sensing lines from the two reference legs terminate outside the primary containment and inside the reactor building. These are discussed in paragraph 7.3.1.2.1. This instrumentation is part of the analog transmitter trip system (ATTS), which is discussed in section 7.8.

The RCIC system is initiated only by RPV water level 2. The signals are derived from relays that are part of the RHR system. The RCIC initiation circuit is arranged in a one-out-of-two-taken-twice logic.

The RCIC system is automatically initiated after the receipt of a RPV water level 2 signal and produces the design flowrate within 45 s. The controls then function to provide a flow of design makeup water to the RPV until the amount of water delivered to the RPV is adequate to restore vessel level (RPV water level 8). At this time, the RCIC system automatically shuts down. The controls are arranged to allow automatic restart at RPV water level 2, remote-manual startup, operation, and shutdown.

The RCIC turbine is functionally controlled as shown on drawing nos. H-24750 through H-24757. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a RCIC system flow signal and adjusts the turbine steam control valve so that design system pump discharge flowrate is obtained. Manual control of the governor is possible

in the test mode; however, the governor automatically returns to automatic control upon receipt of a RCIC system initiation signal. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the RCIC system pump discharge line. The governor controls the position of the hydraulic operator on the turbine control valve which in turn controls the steam flow to the turbine. Hydraulic pressure is supplied by the shaft-driven hydraulic oil pump.

The functional control logics involved in the RCIC turbine start sequence (paragraph 5.5.6.3) are given on drawing no. H-24751. The RCIC initiation signal actuates motor-operated steam supply valve 2E51-F045. In order to reduce the rapid transient on the RCIC turbine, the steam admission valve is equipped with a special contour plug designed to limit steam flow into the turbine during the initial 45% of valve opening. This reduces the possibility of turbine overspeed occurring during the start sequence and is within the 45-s delay assumed in the safety analysis.

The turbine is automatically shut down by tripping the turbine trip and throttle valve closed if any of the following conditions are detected:

- Turbine overspeed.
- High turbine exhaust pressure.
- RCIC isolation signal from logic A or B.
- Low pump suction pressure.
- Manual trip.

In the case of reactor vessel high water level (level 8), the turbine is automatically shut down by tripping the steam supply valve closed. If a reactor vessel water level 2 initiation signal is received after the turbine is shut down due to this high water level signal, the system will automatically restart.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust line. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump which could place it out of service. A turbine trip is initiated for these conditions so that the system can be quickly restored to service if the causes of the abnormal conditions can be found and corrected. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so close that damage occurs before the turbine is shut down. A RCIC overspeed trip will automatically close the turbine trip and throttle valve. There are also several other trip signals possible. All trips, except the RPV water level 8 trip, on the RCIC turbine must be manually reset. With the exception of the mechanical overspeed trip, the turbine may be remotely reset and restarted by operation of the motor operator on the turbine trip and throttle valve. If a mechanical overspeed trip occurs, the power to the turbine trip and throttle valve motor operator is interrupted, and local reset of mechanical linkages at the turbine is required.

There is no specific MCR indication of an overspeed trip condition. There is a turbine trip alarm and an open and closed indication of both the turbine trip and throttle valve and its reset operator. If the reset operator does not function, it must be the result of either a failed operator or a mechanical overspeed trip. Either condition requires local reset at the turbine. Turbine overspeed is detected by a standard turbine overspeed mechanical device. Two pressure transmitters/trip units are used to detect high turbine exhaust pressure; either trip unit can initiate turbine shutdown. One pressure transmitter/trip unit is used to detect low RCIC system pump suction pressure. These pressure transmitters/trip units are part of the ATTS, which is discussed in section 7.8.

High water level in the RPV indicates that the RCIC system has performed satisfactorily in providing makeup water to the RPV. Further increase in level could result in RCIC system turbine damage caused by gross carryover of moisture. The reactor vessel water level 8 setting which trips the turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters/trip units that sense differential pressure are arranged so that both trip units are required to trip to initiate a turbine shutdown.

7.4.1.2.3.2 Logic and Sequencing. The RPV water level 2 trip automatically starts the RCIC system as indicated on drawing no. H-24751. The RPV water level 2 trip is an indication that reactor coolant is being lost and that the fuel is in danger of being overheated.

The RCIC trip is powered by the 125-250-V-dc power system.

Instrument settings for the RCIC system instrumentation and controls are listed in table 7.4-1. The water level setting is far enough below normal levels that spurious RCIC system startups are avoided.

7.4.1.2.3.3 Bypasses and Interlocks. To prevent the turbine pump from being damaged by overheating at reduced RCIC pump discharge flow, a pump discharge bypass is provided to route the water discharged from the pump back to the suppression pool. The bypass is controlled by an automatic, dc motor-operated valve (MOV). At RCIC high flow, the valve is closed; at low flow, the valve is opened. A flow transmitter/trip unit that measures the pressure difference across a flow element in the RCIC pump discharge pipeline provides the signals for low-flow bypass and alarm. A second transmitter provides the signal and flow control. This instrumentation is part of the ATTS, which is discussed in section 7.8.

To prevent the RCIC steam supply pipeline from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain pipeline arrangement just upstream of the turbine supply valve. The controls position valves so that during normal operation steam line drainage is routed to the main condenser. Upon receipt of a RCIC initiation signal, the drainage path is isolated. The water level in the steam line drain condensate pot is controlled by a level switch and a direct-acting solenoid valve which energizes to allow condensate to flow out of the pot.

During test operation, the RCIC pump discharge is routed to the CST. A dc MOV is installed in the pump discharge to CST pipeline. During testing, this valve may be configured such that it

cannot automatically close. This condition will not divert RCIC flow to the CST if an automatic initiation occurs because the HPCI CST test return valve 2E41-F011, which is in series between the RCIC valve and the CST, closes on low RPV water level or a torus suction swap. Also, the operator's ability to close the RCIC valve with the remote-manual switch is unaffected. The valve is interlocked closed if either of the suppression chamber suction valves are not fully closed. Numerous indications pertinent to the operation and condition of the RCIC system are available to the MCR operator (drawing nos. H-24750 through H-24757).

7.4.1.2.3.4 **Redundancy, Diversity, and Separation**. Four RPV water level 2 sensors in a one-out-of-two-taken-twice circuit supply the start signal.

As in the ECCS, the RCIC system is separated into divisions designated I and II. RCIC is a division I system, but the inside steam line valve is in division II; therefore, part of the RCIC logic is treated as division II. The inside valve is an ac-powered valve. The rest of the valves are dc-powered valves. Division I logic is powered by 125-V-dc bus 2A, and the division II logic is powered by 125-V-dc bus 2B. In order to maintain the required separation, RCIC logic relays, cabling, instruments, and manual controls are mounted so that separation from division II is maintained.

7.4.1.2.3.5 **Actuated Devices**. All automatic valves in the RCIC system are equipped with remote-manual test capability so that the entire system can be operated from the MCR. MOVs are provided with appropriate limit and torque switches to turn off the motors when the fully open or fully closed positions are reached. Logic circuitry that controls valves which are automatically closed on isolation or turbine trip signals, with the exception of turbine shutdown due to reactor vessel water level 8, is equipped with manual reset devices so that the valves cannot be reopened without operator action. All required components of the RCIC controls operate independent of ac power.

To ensure that the RCIC system can be brought to design flowrate within 45 s from the receipt of the initiation signal, the following maximum operating times for essential RCIC valves are provided by the valve operation mechanisms:

- RCIC turbine steam supply valve - ≤ 41 s.
- RCIC pump discharge valves - 15 s.
- RCIC pump minimum flow bypass valve - 5 s.

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. The two RCIC steam supply line isolation valves are normally open. They are intended to isolate the RCIC steam line in the event of a break in that line. A normally closed dc motor-operated isolation valve is located in the turbine steam supply pipeline just upstream of the turbine stop valve. Upon receipt of a RCIC initiation signal, this valve opens and remains open until closed by operator action from the MCR.

Two normally open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an ac motor. The valve outside the drywell is controlled by a dc motor. The valves automatically close upon receipt of a RCIC isolation signal.

The instrumentation for RCIC isolation, which is part of the ATTS described in section 7.8, consists of the following:

A. Inside Valve (2E51-F007)

1. Ambient temperature switch (trip unit) - emergency area cooler high temperature. Isolation is initiated immediately.

2. Torus ambient temperature (no trip) - suppression pool area ventilation air inlet and outlet high.

3. Torus differential temperature (trip unit) - isolation occurs after a time delay or manually upon temperature switch activation.

4. Ambient temperature switch (trip unit) - suppression pool area high temperature. Isolation occurs after a time delay or manually upon temperature switch activation.

5. Differential pressure switch (trip unit) - RCIC steam line high flow. Isolation is delayed 3 s.

6. Differential pressure switch (trip unit) - RCIC steam low differential pressure which is indicative of an instrument line break. Isolation is delayed 3 s.

7. Two pressure switches (trip units) - RCIC turbine exhaust diaphragm high pressure. Both switches must activate to isolate.

8. Two pressure switches (trip units) - RCIC steam supply pressure low. Both switches must activate to isolate.

B. Outside Valve (2E51-F008)

A similar set of instrumentation causes the outside valve to isolate with the addition of manual isolation if the low level initiation signal is present.

Three pump suction valves are provided in the RCIC system. One valve lines up pump suction from the CST; the other two line up suction from the suppression chamber. The CST is the preferred source. All three valves are operated by dc motors. Upon receipt of a RCIC system initiation signal, the RCIC pump takes suction from the CST. If the water level in the CST falls below a preselected level, the suppression chamber suction valves automatically open and the CST suction valve automatically closes. Two level switches are used to detect the CST low-water-level condition. Either switch can cause the suppression chamber suction valves to open and the CST suction valve to close. The suppression chamber suction valves also open

automatically if a high-water level is detected in the chamber. Two level switches monitor the water level, and either switch can initiate opening of the suppression chamber suction valves.

Two dc MOV RCIC pump discharge valves are provided in the pump discharge pipeline. Both valves are arranged to open upon receipt of the RCIC initiation signal. One of the pump discharge valves closes automatically upon receipt of a turbine trip signal. The other valve remains open after RCIC initiation until closed by operator action in the MCR.

7.4.1.2.3.6 **<u>Testability</u>**. RCIC may be tested to design flow during normal plant operation. Water is drawn from the CST and discharged through a full-flow test return line to the CST. The discharge valve from the pump to the feedwater line remains closed during the test, and reactor operation remains undisturbed. Design of the control system is such that the RCIC system returns to the operating mode from test if system initiation is required.

7.4.1.2.4 Environmental Considerations

The only RCIC control component located inside the primary containment that must remain functional in the environment resulting from a LOCA is the control mechanism for the inside isolation valve. The environmental capabilities of isolation valves are discussed in paragraph 7.3.2.2.9. The RCIC instrumentation and controls equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate.

Level-sensing instrumentation used as inputs to the RCIC logic from RHR are discussed in paragraph 7.3.1.2.

7.4.1.2.5 Operational Considerations

Core cooling is required in the event that the reactor becomes isolated from the main condensers during normal operation by a closure of the main steam isolation valves (MSIVs). Cooling is necessary because of the core fission product decay heat. Steam is vented through the pressure safety relief valves to the suppression pool. The RCIC system maintains reactor water level by providing the makeup water. Initiation and control are automatic.

The provisions taken in accordance with General Design Criterion 19 of 10 CFR 50, Appendix A, to provide the required equipment outside the MCR for hot and cold shutdown are described in paragraph 7.5.1.4.

A list of setpoints for the RCIC system can be found in table 7.4-1.

7.4.1.3 <u>Analysis</u>

7.4.1.3.1 Conformance to General Functional Requirements

For events other than pipe breaks, the RCIC system has a makeup capacity sufficient to prevent the RPV water level from decreasing to the level where the core is uncovered without using the ECCS.

To ensure to a high degree that the RCIC system operates when necessary and in time to provide adequate core cooling, the power supply for the system is taken from the reliable 125/250-V-dc power system, which is immediately available. Evaluation of instrumentation reliability for the RCIC system shows that no failure of a single initiating sensor either prevents the starting or causes false starting of the system.

A design flow functional test of the RCIC system can be performed during plant operation by taking suction from the demineralized water in the CST and discharging through the full-flow test return line back to the CST.

During the test, the discharge valve to the feed line remains closed and reactor operation is undisturbed. Control system design provides automatic return from the test mode to the operating mode if system initiation is required during testing.

7.4.1.3.2 Conformance to Specific Regulatory Requirements of IEEE 279-1971

A. Single-Failure Criterion (IEEE 279-1971, paragraph 4.2)

The RCIC system, by itself, is not required to meet the single-failure criterion. The control logic circuits for the RCIC system initiation and control are housed in a single relay cabinet, and the power supply for the control logic and other RCIC equipment is from essential dc cabinet 2A.

The RCIC system initiation sensors and wiring up to the RCIC relay logic cabinet do, however, meet the single-failure criterion. Physical separation of instrument lines is provided so that no single instrument rack destruction or single instrument line (pipe) failure can prevent RCIC initiation. Wiring separation between divisions also provides tolerance to single wireway destruction (including shorts, opens, and grounds) in the accident detection portion of the control logic. The single-failure criterion is not applied to the logic relay cabinet or to other equipment required to function for RCIC operation.

B. Quality Components (IEEE 279-1971, paragraph 4.3)

This requirement is described in General Electric Topical Report NEDO-10139, which applies equally to the core spray and RCIC systems.

C. Equipment Qualification (IEEE 279-1971, paragraph 4.4) Environmental

No components of the RCIC control system are required to operate in the drywell environment except for the condensate pots of the RPV level transmitters. The

RCIC steam line isolation valve located inside the drywell is a normally open valve and is, therefore, not required to operate except under special (test) conditions.

Other process sensor equipment for RCIC initiation is located in the reactor building and is capable of accurate operation in the ambient temperature conditions that result from abnormal conditions.

Panels and relay cabinets are located in typical power station control room and/or auxiliary relay room environments; therefore, environmental testing of components mounted in these enclosures is not warranted.

There are no components in the RCIC control system that have not demonstrated their reliable operability in previous applications in nuclear power plant protection systems or in extensive industrial use.

D. Channel Integrity (IEEE 279-1971, paragraph 4.5)

The RCIC system instrument initiation channels meet the single-failure criterion as covered by the discussion of IEEE 279-1971, paragraph 4.2 above, and thus satisfy the channel integrity objective of this paragraph.

By definition (IEEE 279-1971, paragraph 2.2), a channel loses its identity where single-action signals are combined. Therefore, since instrument channels are combined into a single trip system, this paragraph of IEEE 279-1971 does not strictly apply for the RCIC control system.

E. Channel Independence (IEEE 279-1971, paragraph 4.6)

Channel independence for initiation sensors is provided by electrical and mechanical separation. The A and C sensors for RPV level, for instance, are located on one local instrument panel identified as Division I equipment, and the B and D sensors are located on a second instrument panel widely separated from the first and identified as division II equipment. The A and C sensors have a common pair of process taps which are widely separated from the corresponding taps for sensors B and D. Disabling of one or both sensors in one location does not disable the control for RCIC initiation.

F. Control and Protection Interaction (IEEE 279-1971, paragraph 4.7)

The RCIC system is strictly an off-on system, and no signal whose failure could cause need of RCIC can also prevent RCIC from starting. Annunciator circuits using contacts of sensor relays and logic relays cannot impair the operability of the RCIC system control because of the electrical separation between controls. A short between the annunciator wiring and the RCIC control wiring could result in a single ground on the dc control circuit without affecting circuit operability. A short in the annunciator wiring would be cleared by the annunciator circuit protective devices.

G. Derivation of System Inputs (IEEE 279-1971, paragraph 4.8)

The input that starts the RCIC system is a direct measure of the variable that indicates need for core cooling; viz., RPV water level 2.

H. Capability for Sensor Checks (IEEE 279-1971, paragraph 4.9)

All sensors are of the pressure-sensing type and are installed with calibration taps and instrument valves so that testing during normal plant operation or during shutdown is permitted.

Each master trip unit provides continuous readout of the transmitter control current via the meter on its front, which is calibrated in terms of the process variable. Each parameter being monitored has at least one other channel which should show an identical reading. The operator is able to crosscheck the transmitter output currents by comparison and determine whether any transmitters are malfunctioning. If the transmitter completely fails, such that the loop is opened or shorted, the gross-failure system in the trip unit will activate an annunciator in the MCR.

I. Capability for Test and Calibration (IEEE 279-1971, paragraph 4.10)

The RCIC control system is capable of being completely tested under normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be exercised by applying test pressures. Pumps can be started by the appropriate breakers to pump against system check valves (or return to suppression pool through test valves) while the reactor is at pressure. MOVs can be exercised by the appropriate control relays and starters, and all indications and annunciations can be observed as the system is tested.

J. Channel Bypass or Removal from Operation (IEEE 279-1971, paragraph 4.11)

Calibration of a sensor that introduces a single instrument channel trip will not cause a protective function without the coincident trip of a second channel. There are no instrument channel bypasses in the RCIC system. Removal of a sensor from operation during calibration does not prevent the redundant instrument channel from functioning. Removal of an instrument channel from service during calibration will be brief.

K. Operating Bypasses (IEEE 279-1971, paragraph 4.12)

There are several means by which the RCIC system could be deliberately rendered inoperative by plant personnel:

1. The manual opening of feeder breakers to the motor starter for valves, pumps, etc., required to function during RCIC operation.

The manual opening of a breaker for a specific motor. (Deenergizing the control power to the motor starter, deenergizing the valve position lights and, thus, the operator is advised of an abnormal condition.)

2. The manual opening of dc control power feeder breakers. (Tripping or opening a dc control power feeder breaker will give a loss-of-power alarm.)

3. The manual shutting off of instrument line valves in various specific combinations, i.e., either an A and B or a C and D RPV level transmitter line, or a steam supply pressure permissive line. The latter condition is alarmed.

4. Placement of the flow controller from auto to manual operation in the MCR or adjusting the auto setpoint in the incorrect position. Manual operation of the flow controller is provided to allow operator intervention in case the auto portion of the controller fails. The availability of an auto setpoint control on the controller is desirable so that the operator can regulate the flow to maintain water level rather than cycling the turbine between the auto trip and start level setpoints without going to the manual mode of operation. The controller is in the MCR and, therefore, remains under the direct supervision of the MCR operator.

It is considered that all of the above are items under supervisory control and are not intended to be automatically defeated by RCIC initiation signals. Each of the disabling actions specified above would have to be deliberately initiated and would not be performed during normal plant operation.

L. Operating Bypasses (IEEE 279-1971, paragraph 4.12), Automatic Bypasses

The following is a list of automatic bypasses which can render the RCIC system inoperative:

- RCIC steam line isolation signal.

- RCIC turbine trip, which can be caused by the following:

  - Turbine overspeed.

  - RCIC isolation signal.

  - RCIC pump suction pressure low.

  - RCIC turbine exhaust pressure high.

A pump suction pressure transmitter/trip unit is provided to trip the turbine stop valve on low suction pressure. Two pressure transmitters/trip units are provided to monitor turbine exhaust pressure and trip the stop valve on high pressure. Either pressure trip unit indicating high-pressure trips the turbine stop valve. High exhaust pressure and low suction pressure are alarmed in the MCR. These trip

conditions are automatically removed when the trip conditions no longer exist, and the RCIC system automatically restarts if previously started by an auto initiation signal.

The turbine also trips when water level 8 in the RPV is reached. Two level transmitters/trip units are provided to perform this function and are the same type of transmitters/trip units as those used to initiate the ECCS. The logic to trip the steam supply valve requires that both level trip units indicate RPV water level 8. Once initiated, this trip signal will be electrically sealed in until water level drops to the initiate level or is reset manually from the MCR. An indicating light is provided to indicate this sealed-in condition. An RPV water level 8 trip is also alarmed in the MCR but is bypassed when the RCIC system is on remote shutdown control.

In summary, it is considered that there is no violation of the intent of IEEE 279-1971, paragraph 4.12.

M. Indication of Bypasses (IEEE 279-1971, paragraph 4.13)

Indication of bypasses provided is as covered in the discussion of paragraph 4.12.

N. Access to Means for Bypassing (IEEE 279-1971, paragraph 4.14)

Access to motor control centers and instrument valves is controlled as covered in the discussion of paragraph 4.12. Access to other means of bypassing is located in the control room and is, therefore, under the administrative control of the operators.

O. Multiple Setpoint (IEEE 279-1971, paragraph 4.15)

This is not applicable, because all setpoints are fixed.

P. Completion of Protective Action Once It Is Initiated (IEEE 279-1971, paragraph 4.16)

The final control elements for the RCIC system are essentially two position; i.e., MOVs remain open or closed once they have reached their desired position, even though their starter may drop out (which they do when the position or torque switch limit is reached). In the case of pump starters, the automatic initiation signal is electrically sealed in.

Thus, once protection action is initiated (i.e., flow established) it must go to completion or continue until terminated by deliberate operator action or automatically stopped on RPV water level 8 or system malfunction trip signals.

Q. Manual Actuation (IEEE 279-1971, paragraph 4.17)

Each piece of RCIC actuation equipment required to operate (pumps and valves) is capable of manual initiation electrically from the control panel in the MCR.

Failure of logic circuitry to initiate the RCIC system will not affect the manual control of equipment.

However, failures of active components or control circuit failure which produces a turbine trip may disable the manual actuation of the RCIC system. Failures of this type are continuously monitored by alarms.

R. Access to Setpoint Adjustment (IEEE 279-1971, paragraph 4.18)

Setpoint adjustments for the RCIC system trip units are integral to the trip units and are located in the MCR, which will be under the control of supervision or the MCR operator. Setpoint adjustments for level and pressure switches are located on the switches themselves. To gain access to the setting controls on each switch, a cover plate, access plug or sealing device must be removed by operations personnel before an adjustment in trip setting can be made. Control relay cabinets are capable of being locked to prevent unauthorized actuation. Because of these restrictions, compliance with this IEEE 279-1971 requirement is considered complete.

S. Identification of Protective Actions (IEEE 279-1971, paragraph 4.19)

Protective actions are directly indicated and identified by annunciator operation or action of the sensor relay which has an identification tag and a clear glass window front which permits convenient visible verification of the relay position. This combination of annunciation and visible relay actuation is considered to fulfill the requirements of this criterion.

T. Information Readout (IEEE 279-1971, paragraph 4.20)

The RCIC control system is designed to provide the operator with accurate and timely information pertinent to its status. It does not introduce signals into other systems that could cause anomalous indications confusing to the operator. Periodic testing is the means provided for verifying the operability of the RCIC components and, by proper selection of test periods to be compatible with the historically established reliability of the components tested, complete and timely indications are made available. Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the RCIC function is available or operating properly.

In addition to the annunciator alarms shown on the functional control diagram on drawing no. H-24757, alarms are provided to indicate failure of control power to the RCIC system.

In addition to the annunciators, there are other indications on the MCR panel as follows:

- Valve position lights.
- Pump monitor lights.
- Pump discharge pressure indicator.
- An RCIC flow indicator.
- Turbine exhaust line pressure indicator.
- Pump turbine suction pressure indicator.
- Turbine speed indicator.

U. System Repair (IEEE 279-1971, paragraph 4.21)

The RCIC control system is designed to permit repair or replacement of components. Duty cycle was considered in the design of RCIC system devices. Since this duty cycle is composed mainly of periodic testing rather than operation, lifetime is more a matter of shelf life than active life. However, all components are selected for a continuous duty condition with thousands of cycles of operation, which is more severe than that anticipated in actual service. The pump breakers are an exception to this with regard to the large number of operating cycles available. Nevertheless, even these breakers should not require contact replacement for the life of the plant.

Recognition and location of a failed component is accomplished during periodic testing. The simplicity of the logic makes the detection and location relatively easy, and components are mounted in such a way that they can be conveniently replaced in a short time. For example, replacement time for a GE-type HFA relay is < 30 min. Sensors which are connected to the instrument piping cannot be changed so readily, but are required to be connected with separable screwed or bolted fittings. They are changed reasonably in ~ 1 h, which includes electrical connection replacement.

V. Identification (IEEE 279-1971, paragraph 4.22)

In contrast to the protection systems, the RCIC system is not identified in any unique way. All controls and instruments are located in one section of the MCR panel and are clearly identified by nameplates. Relays are located in one panel for RCIC use only. Relays and panels are identified by nameplates.

7.4.1.3.3 Conformance with Requirements of IEEE 323-1971, "General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations"

Compliance with the requirements of IEEE 323-1971 is discussed in section 3.11. The operation of RCIC is not assumed in any accident analysis that would create a harsh environment. Therefore, the only portion of RCIC which must meet the 10 CFR 50.49 requirements is the system isolation function. This is presented in the Plant Hatch Central File.

7.4.1.3.4 Conformance with Requirements of IEEE 338-1971, "Trial-Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems"

Only the paragraphs of IEEE 338-1971 that apply to the design of the RCIC system will be covered:

A. Capability for sensor checks (IEEE 338-1971, paragraph 2.1) is covered in the discussion of paragraph 4.9.

B. Capability for test and calibration (IEEE 338-1971, paragraph 2.2) is covered in the discussion of paragraph 4.10.

7.4.1.3.5 Conformance with Requirements of IEEE 344-1971, "Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations"

Compliance with the requirements of IEEE 344-1971 is discussed in section 3.10.

7.4.1.3.6 Conformance with the Requirements of 10 CFR 50, Appendix A, General Design Criteria (GDC)

- GDC 13 - paragraphs 7.4.1.2.3.1, 7.4.1.2.3.2, and 7.4.1.2.3.3.
- GDC 20 - paragraph 7.4.1.2.3.5.
- GDC 21 - paragraph 7.4.1.2.3.6.
- GDC 22 - paragraph 7.4.1.2.3.4.
- GDC 29 - paragraph 7.4.1.2.3.6.
- GDC 37 - paragraph 7.4.1.2.3.6.

7.4.1.3.7 Conformance with 10 CFR 50, Appendix B

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.4.1.3.8 Conformance with Regulatory Guide 1.22 (February 1972)

A discussion of sensor check testing and calibration is presented in the discussion of paragraphs 4.9 and 4.10 of IEEE 279-1971 (paragraph 7.4.1.3.2).

7.4.2 STANDBY LIQUID CONTROL SYSTEM (SLCS)

7.4.2.1 Design Bases

7.4.2.1.1 Safety Design Bases

A. General Functional Requirements

The major components of the SLCS consist of a storage tank, two positive displacement pumps, two explosive valves, and two check valves between the explosive valves and the reactor, as shown on drawing no. H-26009. The flow path is from the storage tank through the pumps, explosive valves and check valves, and into the reactor to the bottom of the core plate. This system is capable of shutting the reactor down from full power to cold shutdown and maintaining the reactor in a subcritical state at atmospheric temperature and pressure conditions by pumping enriched sodium pentaborate, a neutron absorber, into the reactor.

Dual components and dual circuits are used in portions of the system since this manually-operated system is subject to single failure. Monitoring and testing capabilities have been provided for the components and circuits which are deemed most likely to fail. Power is supplied from the essential buses.

Additional information is provided in subsection 7.1.2.

B. Specific Regulatory Requirements

General Design Criterion 26 of 10 CFR 50, Appendix A, which requires the provision of an independent method of reactivity control, applies. IEEE 323-1971 and IEEE 344-1971 apply to Class 1E components in this system. This equipment does not fall under the regulatory requirements of 10 CFR 50.49 and, therefore, is not required to meet the provisions of that rulemaking.

10 CFR 50.62 paragraph (c)(4) requires the SLCS to have a reactivity control capacity equivalent to that of a system with an 86-gal/min injection flowrate of 13 weight percent unenriched sodium pentaborate into a 251-in. diameter RPV.

The SLCS meets this requirement by using a boron-10 enriched sodium pentaborate solution.

C. As part of the implementation of an alternative source term (AST) (reference subsection 15.1.11), a new design function was added for SLCS to buffer the suppression pool by injection of a sufficient amount of sodium pentaborate solution to the suppression pool to prevent iodine re-evolution following a LOCA. Reference paragraph 4.2.3.4 for further discussion of this new design function.

7.4.2.1.2 Power Generation Design Basis

The system is designed to shut the reactor down from full power to cold atmospheric conditions with sufficient margin to maintain the reactor subcritical at the cold condition.

7.4.2.2 System Description

The instrument and control system for the SLCS is designed to inject liquid soluble neutron absorber solution well above saturation temperature.

7.4.2.2.1 Classification

The SLCS is a backup method of manually shutting down the reactor to the cold subcritical mode independent of the control rod system. Thus, the system is considered a control system and not an engineered safety feature system. The standby liquid control (SLC) process equipment, instrumentation, and controls essential for injection of the neutron absorber solution into the reactor are designed to withstand Seismic Category I earthquake loads. Nonprocess equipment, instrumentation, and controls are designed as a Seismic Category II system.

7.4.2.2.2 Initiating Circuits

The SLCS is initiated in the MCR by turning a keylocking switch to either system A or system B. The key is removable in the centerstop position. When either system is initiated, both explosive valves (F004A and F004B) are fired, and the selected pump C001A or C001B is started. Should the selected pump fail to start, the key switch may be turned to the alternate pump.

7.4.2.2.3 Logic and Sequencing

When the SLCS is initiated, both the explosive valves fire and the pump that has been selected for injection starts.

7.4.2.2.4 Bypasses and Interlocks

There are no bypasses. When the SLCS is initiated to inject soluble neutron absorber into the reactor, the outboard isolation valve of the reactor water cleanup is automatically closed.

7.4.2.2.5 Redundancy and Diversity

The redundancy exists in duplicated pumps, explosive valves, check valves, relief valves, and power supplies.

7.4.2.2.6 Actuated Devices

When the SLCS is initiated to inject soluble neutron absorber into the reactor, one of the two injection pumps and both the explosive valves are actuated.

7.4.2.2.7 Testability

The instrumentation and control system of the SLCS is tested when the system test is performed as outlined in paragraph 4.2.3.4.

7.4.2.2.8 Supporting Systems

The power supply to explosive valve F004A and injection pump C001A is from essential 600-V bus 2C. The power supply to explosive valve F004B and injection pump C001B is from essential 600-V bus 2D. The power supply to the tank heaters and heater controls is connected to the essential 600-V buses 2C and 2D.

7.4.2.2.9 Equipment Environment

The environmental considerations for the instrumentation and control portions of the SLCS are the same as for the active mechanical components of the system. This is discussed in section 3.11 and paragraph 4.2.3.4.

7.4.2.2.10 Operational Considerations

The control scheme for the SLCS can be found on drawing no. H-24721. The SLC is manually initiated in the MCR by inserting the proper key into the keylocking switch and turning it to either system A or system B. The time it takes to complete the injection is between 30 and 90 min. When the injection is completed, the system is manually turned off by returning the keylocking switch to the OFF position.

The provisions taken in accordance with General Design Criterion 19 of 10 CFR 50, Appendix A, to provide the required equipment outside the MCR for hot and cold shutdown is described in section 7.5.

Operator Information

The SLCS indicators are as follows:

A. The system pressure is indicated with an indicator that has a range of 0 to 1800 psig in the MCR.

B. The storage tank level is indicated with an indicator that has a range of near empty to near full, calibrated to read in gallons of liquid storage locally and 0 to 100% level in the MCR.

C. The continuity of the explosive valve dual primer ignition circuit is monitored by measuring a trickle current through the primers. If either of the dual primer or the primer ignition circuits become open circuited, the continuity meter reads downscale.

D. Indicator lights in the MCR show if either of the pumps is running, stopped, or tripped.

E. Indicator lights in the MCR show if either of the explosive valves' firing circuit has an open circuit or not.

F. Indicator lights in the MCR show if service valve F008 is open or closed.

G. Indicator lights on the local panel show if the manually controlled storage tank heater for solution mixing is on or off.

H. Indicator lights on the local panel show if the thermostatically controlled storage tank heater for maintaining solution temperature is on or off.

The SLCS MCR annunciators annunciate when:

- The loss of continuity of either explosive valve primers activates a MCR annunciator.
- The standby liquid storage temperature becomes too hot or too cold.
- The standby liquid tank level is too high or too low.
- The SLC suction piping temperature is too low.

Setpoints

The SLCS has setpoints for the various instruments as follows:

A. The loss-of-continuity meter is set to activate the annunciator just below trickle current that is observed when the primers of the explosive valves are new.

B. The SLCS storage tank high/low temperature switch operates an annunciator in the MCR. The high setting indicates solution temperature above the tank thermostatic controller temperature range. The low setting ensures that the solution is maintained at a safe margin above its saturation temperature to prevent precipitating any sodium pentaborate from the solution.

C. The SLCS storage tank high/low level switch operates an annunciator in the MCR to indicate solution levels outside the administrative limit set in accordance with applicable plant procedures.

D. The thermostatic controller is set to maintain the SLCS suction piping above the saturation temperature of the sodium pentaborate solution. A temperature switch in the suction line will activate an annunciator in the main control room if the solution temperature falls to 10°F below the setting of the thermostatic controller.

7.4.2.3 <u>Analysis</u>

7.4.2.3.1 Conformance to General Functional Requirements

Redundant positive displacement pumps, explosive valves, and control circuits for these components have been provided as described in paragraph 7.4.2.2. This constitutes all the active equipment required for injection of the sodium pentaborate solution. Continuity relays provide monitoring on the explosive valves, and indicator lights provide indication on the main reactor control panel of system status as described in paragraph 7.4.2.2.10. Testability is described in paragraph 7.4.2.2.7. Redundant power sources are described in paragraph 7.4.2.2.8.

7.4.2.3.2 Conformance to Specific Regulatory Requirements

As required by General Design Criterion 26 of 10 CFR 50, Appendix A, the SLCS provides the second independent reactivity control system as qualified in paragraph 4.2.3.4. Qualification of Class 1E electrical equipment in accordance with IEEE 323-1971 and seismic design of Class 1E electrical equipment in accordance with IEEE 344-1971 are covered in sections 3.11 and 3.10, respectively.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

The requirements of 10 CFR 50.62 (c)(4) are met in the manner set forth in paragraph 4.2.3.4.3.

7.4.3 REACTOR SHUTDOWN COOLING SYSTEM

7.4.3.1 Design Bases

A. Safety Design Basis

The instrumentation and control for the reactor shutdown cooling mode of the residual heat removal (RHR) system is designed to:

- Enable the system to remove the residual heat (decay heat and sensible heat) from the reactor vessel during normal shutdown.

- Provide all facilities for manual control of the shutdown cooling system in the MCR.

- Indicate shutdown cooling system response by MCR instrumentation.

B. Power Generation Design Basis

The instrumentation and control is designed to:

- Provide cooling for the reactor during the shutdown operation when the RPV pressure is < ~ 100 psia.

- Cool the reactor water to a temperature that is practical for refueling and servicing operation.

7.4.3.2 System Description

The reactor water is cooled by taking suction from one of the recirculation loops as shown on drawing nos. H-26014 and H-26015. During the shutdown mode, only a portion of the RHR system heat exchanger capacity is required. This allows the remaining portion of the RHR system with its heat exchanger, associated pumps, and valving to be held in the LPCI mode. The LPCI mode portion of the system is shifted to the shutdown mode after the reactor is depressurized so that the proper cooling rate may be achieved with the lower reactor water approach temperature. If it is necessary to discharge a complete core load of reactor fuel to the fuel pool, a means is provided for routing cooling water to the spent-fuel pool cooling system from the RHR heat exchangers. This increases the cooling capacity of the fuel cooling system to handle the heat load for this situation.

7.4.3.2.1 System Identification

The shutdown cooling mode is a function of the RHR system and is placed in operation during a normal shutdown and cooldown.

7.4.3.2.2 Initiating Circuits

The system is initiated only by manual action. The system cannot be actuated unless certain requirements, described in the following subsections, are met.

7.4.3.2.3 Bypasses and Interlocks

To prevent opening the shutdown cooling valves except under proper conditions, the interlocks are provided as shown in table 7.4-2.

The two RHR pumps used for shutdown cooling are interlocked to trip the pumps if the shutdown cooling valves and suction valves from the suppression pool are not properly positioned.

7.4.3.2.4 Actuating Devices

All valves in the shutdown cooling are equipped with remote manual switches in the MCR.

7.4.3.2.5 Testability

The shutdown cooling system pumps of the RHR system may be tested to full capacity during normal plant operation. All valves in the system may be tested during normal plant operation from the remote switches in the MCR.

7.4.3.2.6 Power Sources

The power sources for the instrumentation and controls are as described in the ECCS discussion in paragraph 7.3.1.2.

7.4.3.2.7 Environmental Considerations

The only shutdown cooling control component located inside the drywell that must remain functional in the environment is the control mechanism for the (inboard) isolation shutdown cooling suction valve. The environmental capabilities of isolation valves are discussed in paragraph 7.3.2.2.9. The instrumentation and control equipment located outside the drywell is selected in consideration of the normal and accident environments in which it must operate.

7.4.3.2.8 Operational Considerations

All controls for the shutdown cooling system are located in the MCR. Operator information is provided as described in the RHR discussion of the LPCI mode in paragraph 7.3.1.2.4.

The provisions taken in accordance with General Design Criterion 19 of 10 CFR 50, Appendix A, to provide the required equipment for shutdown outside the MCR is described in paragraph 7.5.1.4.

7.4.3.3 Analysis

7.4.3.3.1 Conformance to General Functional Requirements

The design of the instrumentation and controls meets all the functional requirements of paragraph 7.4.3.1 as follows:

A. Valves

Manual controls and position indicator are provided in the MCR. Interlocks are provided to prevent opening of the valves if shutdown conditions are not met. Interlocks are also provided to close the valves if an isolation signal is present or if high reactor pressure exists.

B. Instrumentation

Shutdown flow indicator is provided. Heat exchanger cooling water and service water temperatures are provided.

C. Annunciation

The following annunciators are provided:

- Valve motor overload.
- Heat exchanger cooling water outlet temperature high.
- Heat exchanger shutdown cooling water high temperature.
- Shutdown suction header high pressure.
- Pump overload.

D. Pumps

Manual controls and stop and start indicators are provided in the MCR. Interlocks are provided to trip the pumps if the shutdown cooling valves are not properly set up.

7.4.3.3.2 Conformance to Specific Regulatory Requirements

There are no specific regulatory requirements for the instrumentation and controls of this system because this subsystem of the RHR system is used only to cool the reactor core for removal of decay heat with the reactor fully shut down and at ~ 100 psi. Alternate shutdown of the reactor is accomplished (assuming failure of the shutdown cooling valves, as discussed in subsection 15.1.9).

Consideration of failure of plant instrument air and loss of cooling water to safe shutdown equipment is given in chapter 15. These systems are not specifically designed for consideration of plant load rejection or turbine trip, but the plant is designed to handle those situations and shut down safely.

7.4.4 LOW-LOW SET RELIEF LOGIC SYSTEM

(See figures 7.4-1, 7.4-2, and 7.4-3.)

7.4.4.1 <u>Design Bases</u>

The low-low set (LLS) relief logic system is designed in accordance with the following requirements:

- The system shall remain operable in the event of a loss-of-offsite power (LOSP). There shall be no interruption of electric power to the LLS system during an LOSP.

- Single-failure consideration for this system shall include any single active mechanical component or electrical component failure. Battery failure shall also be considered.

- After any single failure, the LLS system shall still perform its intended function; i.e., the required number of LLS valves will operate after any single failure. During normal power operation, no single failure shall cause inadvertent seal-in of the arming logic for more than one LLS valve. No single failure shall cause more than one LLS valve to stick open. (See table 5.5-5 for the LLS failure modes and effect analysis.)

- The pneumatic supply shall be available during an LOSP. Accumulators are used to provide the necessary pneumatic supply.

- The system must be testable during normal plant operation.

- The LLS function shall be assigned to only non-automatic depressurization system (ADS) safety relief valves (SRVs), otherwise ADS may cause the valves to reopen before the water level recedes to its original level.

- Manual controls for the LLS system shall be located in the MCR.

- The LLS system must initiate within 1 s after the initial SRV opening, provided RPV pressure is greater than operating pressure.

7.4.4.2 System Description

7.4.4.2.1 Identification and Classification

The LLS relief logic system mitigates the postulated thrust load and shell pressure load concern of subsequent SRV actuations during a small-or intermediate-break LOCA by extending the time between actuations.

The LLS relief logic system, which consists of all Class 1E components, is important to safety.

7.4.4.2.2 Power Source

Power for the LLS system and ADS is obtained from the plant station batteries. The power for LLS logic is also obtained from the plant station batteries and is reduced to 25 V-dc by voltage converters located in the analog transmitter trip system (ATTS) control panels. This power source is Class 1E and is available during an LOSP.

In addition to the drywell pneumatic system, accumulators are used for pneumatic supply. The accumulator for each LLS valve is sized for five cycles. This is sufficient, because the worst-case single failure would fail two valves and only 10 cycles total are required.

7.4.4.2.3 Equipment Design

The LLS system consists of SRV open-close monitors, nuclear boiler pressure instrumentation, a cabinet which house LLS logic relays, solenoid valves, and pneumatic supply. (Accumulators are part of the pneumatic supply.) The SRV open-close monitors are pressure switches which indicate a SRV opening. The nuclear boiler pressure instrumentation consists of transmitters, trip units, and relays. This instrumentation is part of the ATTS, which is discussed in section 7.8.

The solenoid valves and the air accumulators are equivalent to those for the ADS valves which are Class 1E. All other components, including relays, lights, and cabinets, are Class 1E.

All trip unit and logic relay cabinets are located in the MCR.

7.4.4.2.3.1 Initiating Circuits. The SRV open-close monitors and the nuclear boiler pressure instrumentation provide pressure trips for the arming pressure permissive and the LLS setpoints. One transmitter and master trip unit provide the arming permissive trip. A slave

trip unit and another transmitter/master trip unit provide the two-out-of-two for LLS opening logic and one-out-of-two for reclosing logic. The solenoid valves and the drywell pneumatic system are used to pneumatically operate the valves.

The LLS system is functionally controlled as shown in figure 7.4-1.

7.4.4.2.3.2 **Logic and Sequencing**. The LLS logic arms four designated LLS SRVs at their LLS setpoints when any SRV has opened and when concurrent RPV pressure exceeds the scram setpoint. This arming logic is sealed in and annunciated. After arming, nuclear boiler pressure instrumentation controls the solenoid valves so that the LLS SRV valves open and close at their assigned LLS setpoints. Operation continues until manually reset by the MCR operator who then controls reactor pressure below the SRV setpoints.

7.4.4.2.3.3 **Bypasses and Interlocks**. The logic flow for one LLS division is shown in figure 7.4-1. Tailpipe pressure switches and master trip units control the arming relay. This arming relay is the permissive for the master trip unit and the slave trip unit which control the operation of a SRV.

Since the logic requires two independent signals to arm the system, a single failure will not cause inadvertent arming of more than one LLS valve during normal power operation. As shown in figure 7.4-1, inadvertent arming of the channel A arming relay will not cause an inadvertent arming of the channel C arming relay. Channels B and D are not affected since they are separated from channels A and C.

Failure of a solenoid valve or closing signal for a LLS valve may cause the valve to stick open. The channel arrangement uses separate solenoid valves and pressure sensors to control valve closing. Furthermore, the closing logic of LLS is one-out-of-two which assures a valve closure signal with a single failure.

7.4.4.2.3.4 **Redundancy, Diversity, and Separation**. The divisional separation of the LLS design assures that a single active mechanical or electrical component failure or a battery failure will not prevent LLS from performing its intended function.

The system consists of four LLS channels with each channel controlling a separate SRV. The four LLS channels are divided between two separate divisions. The arming logic of the two channels in each division are interlocked, and the two divisions are housed in two separate cabinets. Although all solenoid valves are powered from the ADS cabinet, both divisions of station batteries are used, and each division is separated in accordance with IEEE 384-1974.

7.4.4.2.3.5 **Actuated Devices.** The LLS system pneumatically controls the LLS SRVs. The SRVs have a pneumatic actuator which opens the SRV when pressurized air is applied to the actuator. The air supply to the SRV actuators is controlled by a solenoid valve. When the solenoid valve opens or closes, the SRV opens or closes, respectively.

The control logic of the LLS system electrically controls the solenoids associated with the LLS SRVs.

The solenoid valves actuated by the LLS relief logic system may also be used for manual SRV actuation or by the electrical backup (isolated by fuses) to the mechanical pressure relief setpoint.

7.4.4.2.3.6 **Testability**. The trip units and associated logic are designed to be tested in place, which greatly reduces the required time to perform a surveillance test, therefore, minimizing the time the sensor trip is in the inoperative state. The built-in trip unit calibration system is capable of providing either a stable or transient current that can be used for calibration, functional testing, and time response testing of the trip unit and downstream logic elements.

The nuclear boiler pressure transmitters and the SRV tailpipe pressure switches are tested once per operating cycle when the reactor is out of service for refueling.

7.4.4.2.4 Environmental Considerations

The LLS system relay cabinets are located in the MCR and are subjected to a mild environment only.

The nuclear boiler pressure transmitters are located in the reactor building and are qualified for environments associated with any high-energy line break in the reactor building.

The solenoid valves and SRV monitors (pressure switches) are located in the drywell and are qualified for a LOCA environment.

The LLS hardware was seismically qualified by type testing and similarity analysis to criteria that meet or exceed the requirements outlined in IEEE 323-1974 and IEEE 344-1975.(3)

7.4.4.2.5 Operational Considerations

The LLS relief logic system is automatically initiated for those events involving an SRV blowdown and is required during normal power operation.

No operator action is required for at least 10 min following initiation. However, the operator may elect to terminate system operation sooner based upon the fact that either SRV blowdown is no longer required or that depressurization is manually controlled.

7.4.4.3 Analysis

7.4.4.3.1 Conformance to General Functional Requirements

A plant-specific analysis[2] demonstrated that the LLS relief logic system has the capability of mitigating the postulated loading conditions caused by a small or intermediate break inside the containment. Evaluations[4][5] show that the design will not have detrimental effects on other safety considerations.

7.4.4.3.2 Conformance to Specific Regulatory Requirements

The standards and regulations applicable or partially applicable to the LLS relief logic system design are listed in reference 3. The LLS relief logic system conforms, to the maximum practical extent, to the criteria of these standards and regulations.

The system is installed specifically in response to "Safety Evaluation Report, Mark I Containment Long-Term Program, Resolution of Generic Technical Activity A-7," NUREG-0661.

7.4.5 RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) SYSTEM

7.4.5.1 Design Bases

The design bases for the RHRSW system are presented in paragraph 9.2.7.1.

7.4.5.2 System Description

The RHRSW system ensures cooling water for the RHR heat exchanger which is required to place the reactor in the cold shutdown mode. The RHRSW instrumentation and controls are designed to meet Class 1E criteria.

7.4.5.2.1 Initiation

The RHRSW system can be started from the MCR by manual initiation. A LOCA or an LOSP provides an automatic stop signal to the RHRSW pumps. If offsite power is available, the RHRSW pumps can be started immediately. If offsite power is not available, the RHRSW pumps are manually started, from the MCR, as they are required and as other loads on the essential buses are dropped.

7.4.5.2.2 Redundancy and Separation

The RHRSW system is divided into two redundant divisions physically and electrically separate (according to the criteria specified in paragraph 8.3.1.4.1).

7.4.5.2.3 Testability

Verification of operability of the system may be made by remote manual initiation from the control room. A description of tests and inspections applied to individual components of the system is contained in paragraph 9.2.7.5.

7.4.5.2.4 Supporting Systems

The RHRSW pumps receive power from the essential 4160-V buses. Pump 2A is supplied from 4160-V bus 2E and pumps 2B and 2D are supplied by bus 2G, while bus 2F supplies pump 2C. Control power for pumps 2A, 2C, and 2B, 2D is provided from separate essential 125-V-dc batteries in the diesel building.

7.4.5.3 <u>Analysis</u>

The specific requirements of IEEE 279 to which attention has been directed in the design of the RHRSW system are itemized below by paragraph number as they appear in IEEE 279-1971.

A. Paragraph 4.1: Automatic Initiation

   Automatic initiation of the RHRSW system is not required. The RHRSW system is designed to be manually initiated.

B. Paragraph 4.2: Single Failure

   The single-failure criterion is met by having an independently controlled RHRSW loop for each division.

C. Paragraph 4.3: Quality Assurance

   This requirement is met by following the practices set forth in chapter 17.

D. Paragraph 4.4: Equipment Qualification

   This requirement is met by following the practices set forth in chapter 3.

E. Paragraph 4.5: Channel Integrity

This requirement is met by supplying electrical power to the RHRSW system from essential buses. The routings of power, signal, and control circuits take separate paths. The RHRSW system is a Seismic Category I system.

F. Paragraph 4.6: Channel Independence

This requirement is met by the independent instrumentation and controls provided in the RHRSW system and separate power sources that are employed.

G. Paragraph 4.7: Control Interaction

The requirement of this criteria is met by the complete independence of controls of the two divisions of the RHRSW system.

H. Paragraph 4.8: Direct Inputs

This requirement is met by the derivation of signals that are direct messages of system parameters.

I. Paragraph 4.9: Sensor Checks

This requirement is met by introducing a test signal (in one channel at a time) sufficient to verify that a logic trip is achievable when the parameter deviates beyond the setpoint. Correct response of each sensor is verified by observing that its output indicates a deviation of the parameter beyond the setpoint value.

J. Paragraph 4.10: Testability

Periodic testing of the system as a whole can be performed to ensure the operability of the system (paragraph 9.2.7.5).

K. Paragraph 4.11: Channel Bypass

This requirement is met by the cooling adequacy of one loop fulfilling the minimum requirements of the system, allowing the other loop to be tested during operation without loss of protection.

L. Paragraph 4.12: Operation of Bypasses

This requirement is met by automatically stopping the RHRSW pumps if a LPCI initiation signal is received. This is the only automatic override action the control system performs.

M. Paragraph 4.13: Bypass Indication

This requirement is met by the display provisions in the main control room which indicate the operational state of the RHRSW system.

N. Paragraph 4.14: Bypass Access

This requirement is met by the administrative control that is imposed on use of the RHRSW system.

O. Paragraph 4.15: Multiple Setpoints

This requirement is not applicable to the RHRSW system.

P. Paragraph 4.16: Action Completion

This requirement is satisfied by the functional characteristics of the controls of the RHRSW system.

Q. Paragraph 4.17: Manual Initiation

The RHRSW system is normally manually initiated.

R. Paragraph 4.18: Setpoint Access

This requirement is satisfied by the administrative control that is imposed on use of the setpoint adjustments.

S. Paragraph 4.19: Identification

This requirement is satisfied by the indicating lamps and sequential recorders that the design incorporates to indicate the state of the RHRSW system and its valves and pumps.

T. Paragraph 4.20: Information Readout

This requirement is satisfied by the readout instruments provided to display temperature, pressure, and flow parameters in the RHRSW system.

U. Paragraph 4.21: System Repair

This requirement is met by the readily identifiable modular design of the instrumentation and control components.

V. Paragraph 4.22: Identification

This requirement is not applicable to the RHRSW system; however, the RHRSW system follows the standard system described in paragraph 8.3.1.5.

The requirements of Regulatory Guide 1.22 are met on the basis of the manual test and control provisions that the RHRSW system design incorporates.

Evaluation of the RHRSW system against criteria of 10 CFR 50, Appendix A and Appendix B, are as follows:

A. General Design Criterion (GDC) 21

The RHRSW system provides assurance that, through its standby redundancy, each loop has sufficient reliability to fulfill the single-failure criterion. No single component failure, maintenance operation, calibration operation, or test to verify operational availability impair the ability of the system to perform its intended safety function. There is sufficient electrical and physical separation between channels and between trip logic circuits monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability to respond correctly. The functional reliability of the system is enhanced by early detection of malfunctioning components through routing tests.

B. GDC 22

Physical separation, separate power feeds, and separate controls are provided for the two cooling loops. This ensures that each loop of the RHRSW system (providing the necessary minimum cooling capacity) is available for the required safety function. Details of separation criteria and independence are contained in paragraph 8.3.1.4.1.

C. GDC 23

Since the two loops are independent, failure of one loop does not affect operation of the other loop.

D. GDC 24

Since no signals required for control of the reactor are used for control of the RHRSW system, this criterion is satisfied.

REFERENCES

1. "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22154-1, General Electric Company, July 1983.

2. "Plant Unique Analysis Report for E. I. Hatch Nuclear Plant Unit 2 Mark I Containment Long-Term Program," Revision 1, September 1983.

3. "Analog Trip System Qualification Report," NEDC-30039-1, General Electric Company, January 1983.

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

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

TABLE 7.4-1

RCIC INSTRUMENT SPECIFICATIONS

RCIC Function	Instrument	Trip Settings	Range
RPV water level - high (level 8) [b]	Differential pressure transmitter/trip unit	(a)	0 - 60 in.
Turbine exhaust pressure - high	Pressure transmitter/ trip unit	≤ 45 psig	0 - 250 psig
RCIC system pump suction pressure - low	Pressure transmitter/ trip unit	≤ 12.6 in. Hg vacuum	30 in. Hg vacuum/40 psig
RCIC system pump suction pressure - high	Pressure switch	≤ 75 psig[d]	0 - 100 psig
RPV water level - low, low (level 2) [b]	Differential pressure transmitter/trip unit	(a)	-150/0/+60 in.
RCIC steam supply line pressure - low	Pressure transmitter/ trip unit	(a)	0 - 1200 psig
Turbine overspeed	Centrifugal device	≤ 5625 rpm	-
CST level - low[c]	Float-type level switch	(a)	-
Suppression pool water level - high	Float-type level switch	(a)	-

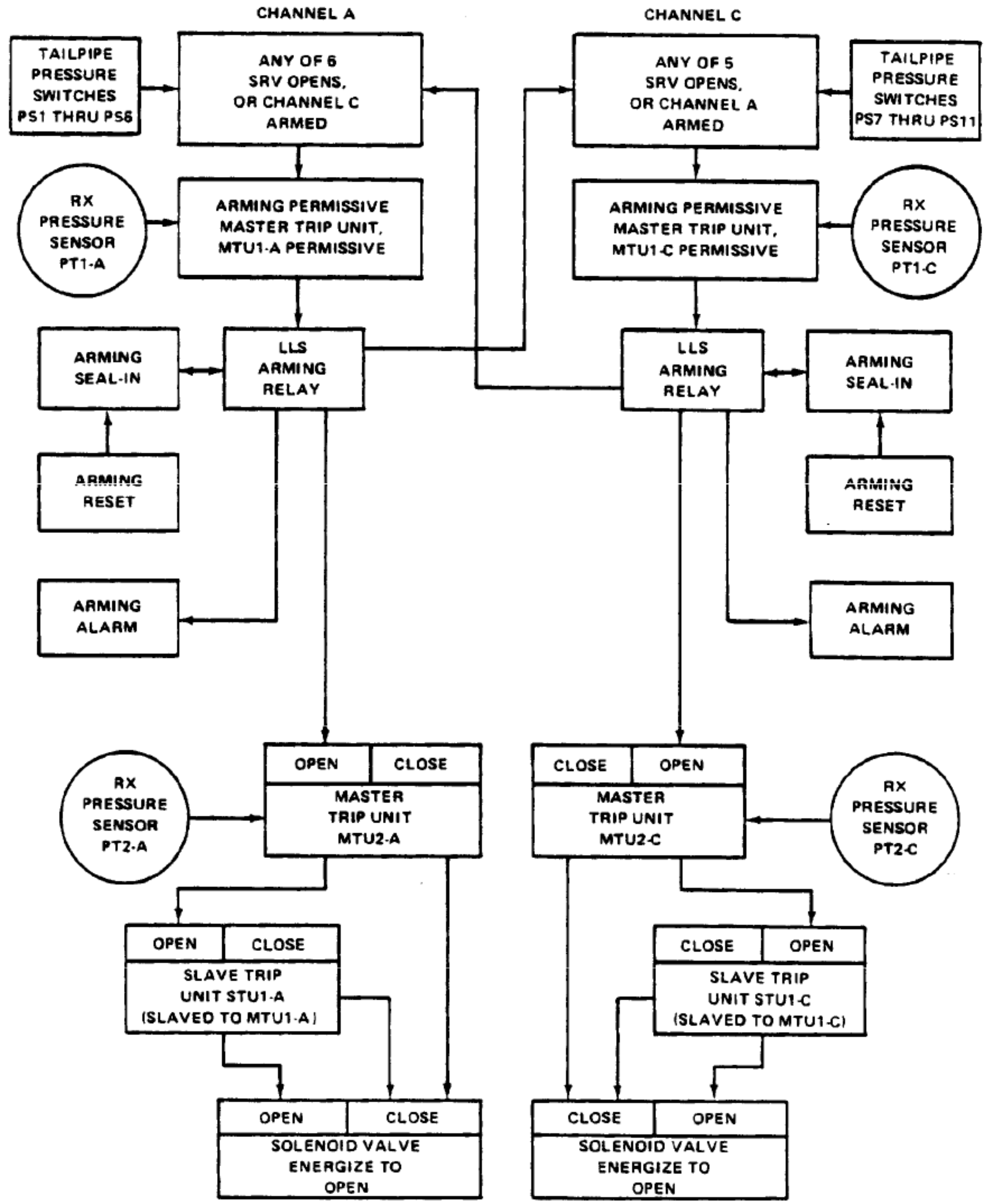
a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Referenced to instrument zero; see figure 5.4-2.
c. Referenced to CST bottom.
d. The value listed is actual trip setpoint; see Instrument Setpoint Index.

TABLE 7.4-2

REACTOR SHUTDOWN COOLING BYPASSES AND INTERLOCKS

Valve Function Manual Open	Reactor Pressure Exceeds Shutdown	Isolation Valve Closure Signal
Inboard suction isolation	Cannot open	Cannot open
Outboard suction isolation	Cannot open	Cannot open
Reactor injection	Can open	Cannot open

Valve Function Automatic Close Manual Close		
Inboard suction isolation	Closes automatically and manually	Closes automatically and manually
Reactor injection	Closes manually	Closes automatically and manually



ACAD 2070401

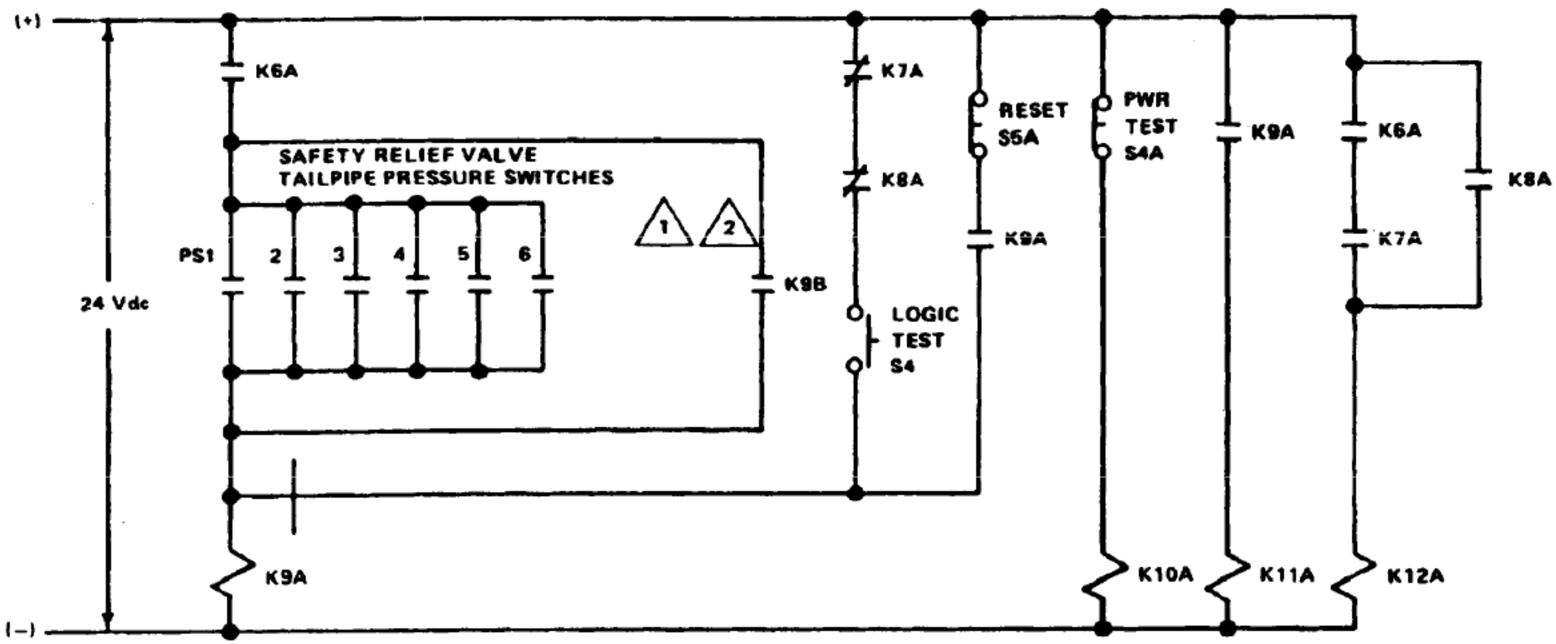
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

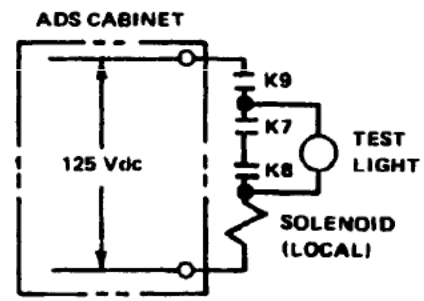
LLS RELIEF LOGIC DIAGRAM

FIGURE 7.4-1



NOTES:

1. CHANNEL B HAS FIVE PRESSURE SWITCHES.
2. DIVISIONS 1 AND 2 USE RELAY CONTACTS FROM THE SAFETY RELIEF VALVE MONITOR SYSTEM (FIVE CONTACTS IN A AND SIX CONTACTS IN CHANNEL D).
3. DEVICE NUMBERS ILLUSTRATIVE (NOT MPL NUMBERS).



ACAD 2070402

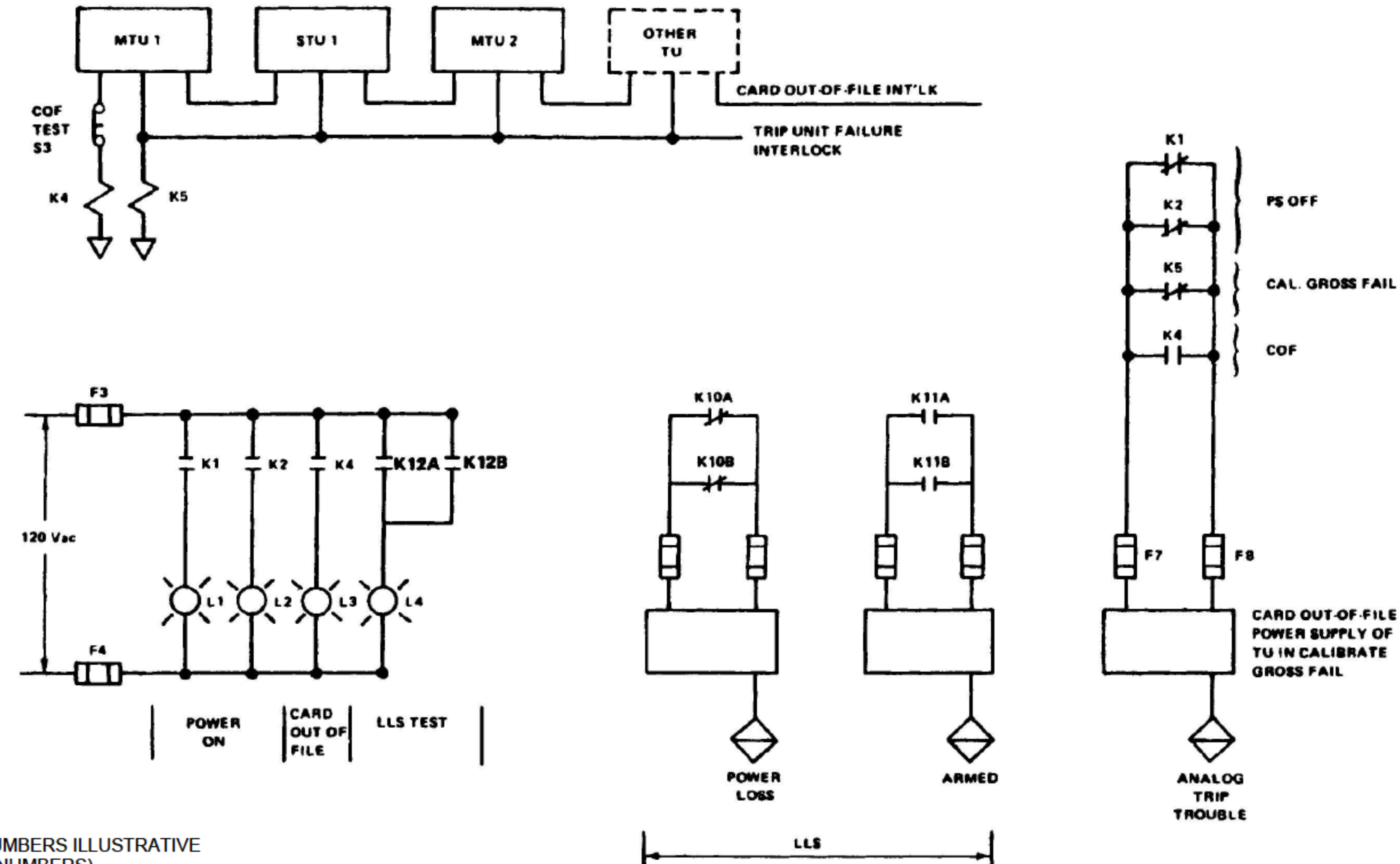
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LLS LOGIC FOR CHANNEL C
(TYPICAL FOR CHANNELS B, A, AND D)

FIGURE 7.4-2



NOTE:
DEVICE NUMBERS ILLUSTRATIVE
(NOT MPL NUMBERS)

ACAD 2070403

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CHANNELS A AND C INDICATORS
(TYPICAL FOR CHANNELS B AND D)

FIGURE 7.4-3

7.5 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

7.5.1 DESCRIPTION

A description of the instrumentation that provides information to the operator to enable him to perform required safety functions is provided in this subsection.

The title of this section, Safety-Related and Power Generation Display Instrumentation, is not intended to suggest that the equipment described does not satisfy safety requirements. Much of the instrumentation available to provide information to the operator performs a dual function (being used mostly during normal operation and also when required for safety purposes) hence, the title. Only the instrumentation related to the performance of safety functions is described, while all other instrumentation required solely for power generation purposes is excluded. Further detailed description and qualification of instrumentation identified in this section are given by reference to other Final Safety Analysis Report (FSAR) subsections, e.g., subsection 7.6.4, Primary Containment Atmosphere Monitors.

A discussion of HNP-2 conformance to Regulatory Guide 1.97 is provided in subsection 7.5.3.

7.5.1.1 Normal Operation

The normal plant process variable indicators and recorders are described in section 7.6 and are shown on the piping and instrumentation designs for the nuclear steam supply system (NSSS). Information channel ranges and indicators are selected on the basis of giving the operator the necessary information, during expected operational perturbations, to perform all the normal plant maneuvers and to be able to track all the process variables pertinent to safety. A description of control rod position indication is given in subsection 7.7.1.

7.5.1.2 Anticipated Operational Occurrences (AOOs)

The ranges of indicators and recorders provided are capable of covering the extremes of process variables and providing necessary information to enable the operator to perform required safety functions.

7.5.1.3 Accidents

Information readouts are provided to accommodate events up to and including a loss-of-coolant accident (LOCA). These readouts are designed from the standpoint of operator action, information, and event tracking requirements, thus providing assurance that all other credible event or incident requirements are covered.

7.5.1.3.1 Initial Accident Event

The design basis of all engineered safety features (ESFs) to mitigate accident event conditions takes into consideration that no operator action or assistance is necessary for the first 10 min of the event. This requirement makes it mandatory that all protective action necessary in the first 10 min be automatic. Therefore, although continuous tracking of process variables is available, no operator action based on them is required for 10 min.

7.5.1.3.2 Post-Accident Tracking

The primary containment indication complies with the recommendations of Branch Technical Position EICSB 23, with the following exceptions:

A. The systems comply with the requirements of the Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971, except for the post-accident tracking instrumentation which does not initiate a protective action; therefore, the requirements of paragraphs 4.1, 4.16, and 4.17 do not apply.

B. The instrumentation was qualified in accordance with IEEE Standard 323-1971. Additional information on environmental qualifications is discussed in section 3.11.

C. The recorders in the main control room (MCR) are Seismic Category I qualified, and they meet the requirements of IEEE Standard 344-1975.

D. Seismic Category I indicators are provided in the MCR, and they meet the requirements of IEEE Standard 344-1971.

The Georgia Power Company (GPC) commitment on post-accident monitoring for Hatch Nuclear Plant-Unit 2 (HNP-2) was started originally in the Preliminary Safety Analysis Report. This statement committed GPC to provide a number of instrumentation systems to supply the operator with remote monitoring for post-LOCA conditions within the primary containment. The commitment took exception to IEEE Standard 279, design requirements 4.3 and 4.4, recorders and indicators.

A meeting was held with the Nuclear Regulatory Commission (NRC) on August 17, 1971. This meeting concerned HNP-2 where each design requirement of IEEE Standard 279 was reviewed and supported the exceptions taken to IEEE 279 design requirements 4.3 and 4.4.

GPC further committed itself to provide redundant Seismic Category I indicators in the MCR. This further commitment was discussed with the NRC staff in a meeting held in Bethesda, Maryland on April 28, 1976. The nonseismic post-accident monitors were replaced with instruments and recorders that were seismically qualified in accordance with IEEE Standard 344-1971.

The following process instrumentation provides information to the operator for use in monitoring reactor and primary containment conditions after a LOCA:

- Reactor pressure vessel (RPV) water level sensors.

- RPV pressure sensors.
- Primary containment instrumentation.

A. RPV Water Level

RPV water level is monitored by two shroud-level transmitters designed to be operable during and after a LOCA.

Two shroud water level signals are transmitted from two independent differential pressure transmitters to trip units located in the MCR. The water level signals are then retransmitted to one indicator and one recorder located in the MCR. The differential pressure transmitters have one side connected to a condensing-type chamber reference leg and the other side connected directly to a vessel nozzle for the variable leg. The water level system is uncompensated for variation in reactor water density and is calibrated to be most accurate at operational pressure and temperature conditions. The range of the recorded and indicated level is from 17 in. below the bottom of the dryer skirt down to a point just below the bottom of active fuel. The recorder is powered by instrument ac buses feeding from the two standby ac buses. The indicator and the instrument loops for the recorder and the indicator are powered by the analog transmitter trip system (ATTS) cabinets which house the trip units. (See section 7.8 for the ATTS cabinet power sources.) Transmitters and trip units monitor the wide-range water level and provide signals to 2 two-pen recorders located in the MCR; one of the pens records the wide-range RPV water level and the other records RPV pressure. The water level transmitters are connected to the hot reference, which is susceptible to boiloff during accident conditions and is, therefore, not taken credit for. The feedwater control system has other RPV water level recorders and indicators in the MCR. The transmitters and trip units are part of the ATTS, which is discussed in section 7.8.

B. RPV Pressure

Two reactor pressure signals are transmitted from two independent pressure transmitters to trip units located in the MCR. The RPV pressure signals are then transmitted to 2 two-pen recorders in the MCR. One of the pens records pressure, and the other records the wide-range RPV water level. The range of recorded pressure is from 0 to 1500 psig. The feedwater control system has other pressure signals recorded in the MCR. This range is sufficient to include the safety limit pressure. The transmitters and trip units are part of the ATTS, which is discussed in section 7.8.

C. Primary Containment Indication

The following instrumentation provides indication to the operator for use in monitoring primary containment conditions after a LOCA:

- Drywell pressure.
- Drywell temperature.
- Drywell radiation.
- H_2 and O_2 analyzer.
- Suppression pool pressure.
- Suppression pool temperature.
- Suppression pool water level.

Redundant, Seismic Category I indicators and recorders are provided in the MCR for all the above instrumentation.

7.5.1.3.3 Safety Interfaces

The balance-of-plant (BOP) NSSS safety interfaces for the MCR panels are the signals from all safety-related BOP equipment and the associated wire and cable which lie outside the NSSS.

The component requirements for the MCR panels and connecting wire and cable are discussed in section 3.11. The BOP equipment signals to the MCR panels are condensate storage tank water level, radiation level at the off-gas system release vent incoming source voltage, and the fuel level in the diesel fuel oil storage tanks.

7.5.1.4 <u>Special Event - MCR Uninhabitability</u>

7.5.1.4.1 Criteria

It is possible to carry out the reactor shutdown functions from outside the MCR and to bring the reactor to cold condition in an orderly fashion in compliance with General Design Criterion (GDC) 19 of 10 CFR 50, Appendix A. MCR uninhabitability is analyzed in section 15.4.

7.5.1.4.2 Remote Shutdown Panel

The remote shutdown panel is located in the [redacted] The remote shutdown system panel is designed to comply with the requirements of Safety Class 3, Seismic Category I, and Quality Group C. The following systems have instrumentation and controls on the remote panel, as shown on drawing nos. A-21725 (sheets 1 and 2), A-21726 (sheets 1 through 8), H-51357, and H-51358.

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

To comply with GDC 19, the remote shutdown panels must be capable of bringing and maintaining the plant in a shutdown condition from the scenario described below in paragraph 7.5.1.4.3. The controls required to accomplish these actions involv [redacted].

7.5.1.4.3 Conditions Assumed to Exist as the MCR Becomes Inaccessible

A. The plant is operating initially at, or less than, design power.

B. Loss of offsite ac power is considered unlikely but credible. The remote shutdown panel is powered from an essential bus so that standby ac power is automatically supplied by the diesel generator in the event of loss-of-offsite power. Manual controls of the diesel generator are also available in the diesel generator building.

C. A LOCA is not assumed; therefore, complete control of ESF systems from outside the MCR is not required.

D. Plant personnel evacuate the MCR.

E. The MCR continues to be inaccessible during the entire shutdown procedure.

F. The event that causes the MCR to become inaccessible is assumed to be such that the operator can manually scram the reactor before leaving the MCR. As a backup, the operator can manually scram the reactor locally by deenergizing the reactor protection system (RPS) power supplies.

G. The main turbine pressure regulators may be controlling reactor pressure via the bypass valves; however, in the interest of simplicity and safety, it is assumed that this function is lost. Therefore, main steam line isolation is assumed to occur at 850-psig turbine inlet pressure and RPV pressure is relieved through the safety relief valves to the suppression pool. The feedwater control system is also assumed to be unavailable due to reactor isolation.

H. Reactor water is made up by the RCIC system.

I. The dc services are supplied from at least one 125/250-V plant dc power system for each essential system or equipment item in the remote shutdown system.

7.5.1.4.4 Description

The system provides remote control for reactor systems needed to carry out the shutdown function from outside the MCR and to bring the reactor to cold condition in an orderly fashion. This system also provides a variation to the normal system used in the MCR, thus permitting the shutdown of the reactor when feedwater is unavailable and the normal heat sinks (turbine and condenser) are lost.

Automatic activation of safety relief valves and the RCIC system bring the reactor to a hot shutdown condition. During this phase of shutdown, the suppression pool is cooled by operating the RHR system in the suppression pool cooling mode. Reactor pressure is controlled, and core decay and sensible heat is rejected to the suppression pool by relieving steam pressure through the relief valves. RPV water inventory will be maintained by the RCIC system.

Manual operation of the safety relief valves cools the reactor and reduces its pressure at a controlled rate until RPV pressure becomes so low that the RCIC system discontinues operation. This condition is reached at 50- to 100-psig RPV pressure. The RHR system is then operated in the shutdown cooling mode wherein the RHR system heat exchanger is connected directly into the reactor water circuit to bring the reactor to the cold, low-pressure condition.

The only equipment requiring qualification to 10 CFR 50.49 in the remote shutdown panels are the control and transfer switches. Refer to the Plant Hatch Central File for the exact switches.

7.5.1.4.5 Procedure for Reactor Shutdown from Outside the MCR

A. If evacuation becomes necessary, the operator will scram the reactor by depressing the manual scram pushbuttons and placing the mode switch to shutdown.

B. If the reactor is shut down, the operator will trip the main turbine. The pressure regulator will, under normal conditions, control the reactor pressure while rejecting heat (steam) through the turbine bypass valves. The feedwater control system will control RPV water level.

C. If the reactor is not shut down, the operators will insert a manual scram either by opening breakers CB3A and CB3B at the RPS distribution panel or by tripping the scram discharge volume level magnetrol switches, 2C11-NO13A, B, C, and D. If these methods fail to shut down the reactor, the operator will initiate the standby liquid control system prior to suppression pool temperature reaching 110°F.

D. If indications exist of a group 1 isolation, operators will close the inboard main steam line isolation valves by opening breaker CB5A in RPS distribution cabinet 2C71-P001 and by opening breaker 17 in distribution cabinet 2R25-S001. If the main steam line isolation valves are closed, the RCIC system will be used to control RPV water level.

E. Transfer switches at the key-controlled remote panel will be operated to transfer control to the remote shutdown panel.

F. Safety relief valve operation will be as indicated on drawing no. H-26000. RPV water level will start to drop rapidly or slowly depending on prior power level and elapsed time from scram.

G. The operator will start the RCIC system manually before level 2 (drawing nos. H-26000 and H-26001) is reached and will monitor the water level thereafter. The water level will continue to fall.

H. RPV water level will reach its lowest point at about 444-in. above vessel zero if the RCIC system was initiated at low level. The level will then start to rise as a result of RCIC system flow. Pressure relief will be through one safety relief valve in automatic intermittent operation.

I. RPV water level will be returned to normal by operation of the RCIC system.

J. One safety relief valve will still be in automatic intermittent operation. The RCIC system turbine will automatically trip.

K. Reduction of RPV pressure will be started by manually actuating one safety relief valve. While activating the safety relief valves, the operator will observe the RPV water level and suppression pool temperature.

L. Safety relief valves will be closed off when level drops below level alarm point. The reactor cooldown rate will not exceed 100°F/h. RPV water level varies between low-alarm point and high-alarm point.

M. The RHR system with one pump, one heat exchanger, and the associated service water system will be used to cool the suppression pool.

N. The operator will activate two safety relief valves to maintain reduction of pressure to 250 psig while observing that pool temperatures do not exceed 140°F, unless the reactor pressure decreases to < 250 psig.

O. RPV pressure will be reduced to 100 psig while assuring that the suppression pool temperature does not exceed 170°F.

P. The RHR system will be placed in the shutdown cooling mode and the system flushed for several minutes by pumping water into the suppression pool before returning it to the RPV. RHR operation will continue until the reactor is in the cold, low-pressure condition.

Q. Normal RPV water level will be maintained after being placed in the shutdown cooling mode.

7.5.2 ANALYSIS

The safety-related and power generation display instrumentation provides adequate information to allow operators to make correct decisions as bases for manual control actions permitted under normal, AOO, and accident conditions.

Information instrumentation having no direct input to ESF systems, except through the operator as a link, is considered to be outside the scope of existing IEEE standards. However, insofar as practical, instruments are selected from those types qualifiable under IEEE Standard 279-1971 and IEEE Standard 323-1971. Redundancy and independence or diversity are provided in all of those information systems used for the basis of operator-controlled safeguards action.

The RPV water level and pressure transmitters are mounted on local panels. The transmitters are designed to operate during normal operation, accident, and post-accident environmental conditions. There are two complete and independent channels of wide-range RPV water level and pressure with each channel having its readout on a separate recorder. The recorders are located in the MCR on the emergency core cooling system (ECCS) benchboard. One recorder is with the Division I systems, and the other recorder is with the Division II systems.

The accuracy of the RPV water level and pressure indicators in the MCR is ± 2.0% of monitored range. The design is adequate to provide for accurate reactor water level and reactor pressure information during normal operation, AOO, and accident conditions.

7.5.2.1 Normal Operation

Subsection 7.5.1 describes the basis for selecting ranges for instrumentation and, inasmuch as AOO or accident conditions monitoring requirements exceed those for normal operation, the normal ranges are covered adequately.

7.5.2.2 AOOs

AOOs will result in conditions lesser in consequence than those defined to be accident conditions in paragraph 7.5.2.3. Proper accident tracking, therefore, qualifies AOO tracking.

The variety of indications that may be utilized to verify that shutdown and isolation safety actions have been accomplished as required (paragraph 7.5.1.3.2) are considered adequate to comply with requirements of IEEE Standard 279-1971.

7.5.2.3 Accidents

The LOCA is the most extreme operational event. Information readouts are designed to accommodate this event from the standpoint of operator action, information, and event-tracking requirements, therefore, covering all other design basis events or incident requirements.

7.5.2.3.1 Initial Accident Event

The design basis of all ESFs to mitigate accident conditions takes into consideration that no operator action or assistance is required or recommended for the first 10 min of the event. This requirement makes it mandatory that all protective action necessary in the first 10 min be automatic. Therefore, although continuous tracking of variables is available, no operator action based upon them is intended.

7.5.2.3.2 Post-Accident Tracking

Operator action is optional after 10 min. RPV water level and pressure, and ECCS process instrumentation provide information to the operator after a design basis accident (DBA) for use in monitoring reactor conditions within the primary containment.

A. RPV Water Level and Pressure

RPV water level and pressure instrumentation, described in paragraph 7.5.1.3.2, is redundant, electrically independent, and operable during and after a LOCA. AC Power is from essential DC inverters powered from the Station Battery Power System or essential AC buses. This instrumentation complies with independence and redundancy requirements of IEEE Standard 279-1971.

B. ECCS Process Instrumentation

Performance of emergency core cooling following an accident may be verified by observing redundant and independent indications as described in paragraph 7.5.1.3.2 and fully satisfies the need for post-accident surveillance of these variables. The redundancy and independence provided is such as to meet the single-failure criteria of IEEE Standard 279-1971 and to obtain a high degree of reliability.

7.5.2.4 Special Event - Shutdown from Outside the MCR

Analysis of reactor shutdown from outside the MCR is included in paragraph 7.5.1.4.

7.5.3 INFORMATION SYSTEMS IMPORTANT TO SAFETY (HNP-1 AND HNP-2)

7.5.3.1 Introduction

This section describes Regulatory Guide (RG) 1.97 requirements, as well as the HNP-1 and HNP-2 safety-related and nonsafety-related information systems that are required to assure compliance with RG 1.97, Revision 2. Conformance to RG 1.97 requirements is provided by HNP-1 and HNP-2 instrumentation listed in table 7.5-1. Master parts list (MPL) numbers preceded by a unit designator identify instrumentation. Instrumentation located in both HNP-1 and HNP-2 with identical MPL numbers is preceded by a 1, 2.

7.5.3.2 Description of Information Systems

The safety analysis and evaluations define the DBA event scenarios for which preplanned operator actions are required. Accident-monitoring instrumentation is necessary to permit the operator to take required actions to address these analyzed situations. Instrumentation is needed to determine that safety systems are functioning properly and to provide information on radioactive releases. Instrumentation is also necessary for unforeseen situations (i.e., to ensure that, should plant conditions evolve differently than predicted by the safety analyses, the MCR operating staff has sufficient information to evaluate and monitor the course of the event). Additional instrumentation is also needed to indicate to the operating staff whether the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), or the reactor primary containment has degraded beyond the prescribed limits defined in the plant safety analyses and other evaluations.

RG 1.97 has identified five classifications (types) of variables to provide this instrumentation. Each type of variable is discussed further in paragraph 7.5.3.3

Three categories of design and qualification are identified in RG 1.97, Revision 2.

A. Category 1 provides the most stringent requirements and is intended for key variables.

B. Category 2 provides less stringent requirements and generally applies to instrumentation designated for indicating system operating status.

C. Category 3 is intended to provide requirements that will ensure that high-quality off-the-shelf instrumentation is obtained and applies to backup and diagnostic instrumentation. It is also used where state of the art will not support requirements for more highly qualified instrumentation.

Paragraph 7.5.3.4 describes the specific requirements for each category.

Table 7.5-1, which describes HNP's conformance to RG 1.97, Revision 2, summarizes the following information for each variable identified:

- Variable measured.
- Type.
- Category.
- Plant-unique identification number of sensor and receiver.
- Notes and remarks.

The five variables are given in the following paragraphs.

1. Type A Variables

   Variables that provide information needed by the operator to perform manual actions identified in the operating procedures for which no automatic control is provided are designated type A. These variables are restricted to preplanned actions for DBAs.

2. Type B Variables

   Variables needed to assess that safety functions are being accomplished or maintained, as identified in the safety analysis and other evaluations, are designated type B.

3. Type C Variables

   Variables that provide information to indicate the potential for, or the actual, breaching of the barriers to fission product release; i.e., fuel cladding, the RCPB, or the containment, are designated type C.

4. Type D Variables

   Variables that provide information to indicate the operation of individual safety systems and other systems important to safety are designated Type D.

5. Type E Variables

   Variables that are required for use in determining the magnitude of the postulated releases and continually assessing any such releases of radioactive material are designated Type E.

7.5.3.3 Variable Types

Accident-monitoring variables and information display channels are required to enable the MCR operating staff to perform the functions defined by Type A, B, C, D, and E classifications in RG 1.97, Revision 2.

The five classifications (types) of variables discussed below are not mutually exclusive, in that a given variable or instrument may be included in one or more types. When a variable is included in one or more of the classifications, the equipment monitoring this variable meets the requirements of the highest category identified.

7.5.3.3.1 Type A Variables

Type A variables provide the primary information required to permit the MCR operator to take specific manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for DBAs. Primary information is information that is essential for the direct accomplishment of the specified safety functions; it does not include those variables that are associated with contingency actions that may also be identified in written procedures.

7.5.3.3.2 Type B Variables

Type B variables provide information to indicate whether plant safety functions are being accomplished. Plant safety functions are:

- Reactivity control.
- Core cooling.
- Maintaining reactor coolant system (RCS) integrity.
- Maintaining containment integrity (including radioactive effluent control).

7.5.3.3.3 Type C Variables

Type C variables provide information to indicate the potential for, or the actual, breaching of the barriers to fission product releases. The barriers are:

- Fuel cladding.
- PCPB.
- Containment.

7.5.3.3.4 Type D Variables

Type D variables provide information to indicate the operation of individual safety systems and other systems important to safety. These variables help the operator make appropriate decisions in using the individual systems important to safety in mitigating the consequences of an accident.

7.5.3.3.5 Type E Variables

Type E variables are monitored as required for use in determining the magnitude of the release of radioactive material and continually assessing such releases.

7.5.3.4 Variable Categories

Types A, B, C, D, and E accident-monitoring instrumentation is subdivided into three categories. Descriptions of the three categories are given below.

7.5.3.4.1 Design and Qualification Criteria - Category 1

The instrumentation should be environmentally and seismically qualified. Qualification is applicable to the complete instrumentation channel, from sensor to display, where the display is a direct-indicating meter or recording device. Where the instrumentation channel signal is to be used in a computer-based display, recording, and/or diagnostic program, qualification applies from the sensor to, and includes, the channel isolation device.

Instrumentation should continue to read within the required accuracy following, but not necessarily during, a safe shutdown earthquake (SSE).

No single failure within either the accident-monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with failures that are a condition or result of a specific accident, should prevent the operators from being presented the information necessary to determine the safety status of the plant and to bring the plant to, and maintain it in, a safe condition following the accident. Where failure of one accident-monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function, additional information should be provided to allow the operators to deduce the actual conditions in the plant.

Redundant or diverse channels should be electrically independent and physically separated from each other and from equipment not classified important to safety, up to and including any isolation device. At least one channel should be displayed on a direct-indicating or recording device.

Instrumentation should be energized from station standby power sources and should be backed up by batteries where momentary interruption is not tolerable.

The instrumentation channel should be available prior to an accident except as provided in paragraph 4.11, Exemption, as defined in IEEE Standard 279 or as specified in Technical Specifications.

Continuous indication (it may be by recording) display should be provided. Where two or more instruments are needed to cover a particular range, overlapping instrument span should be provided.

Recording of instrumentation readout information should be provided. Where direct and immediate trend or transient information is essential for operator information or action, the recording should be continuously available on dedicated recorders; otherwise, it may be continuously updated, stored in computer memory, and displayed on demand. Intermittent displays such as data loggers and scanning recorders may be used if no significant transient response information is likely to be lost by such devices.

7.5.3.4.2 Design and Qualification Criteria - Category 2

The instrumentation should be environmentally qualified. Seismic qualification may be needed, provided the instrumentation is part of a safety-related system. Where the channel signal is to be processed or displayed on demand, qualification applies from the sensor through the isolator/input buffer. The location of the isolation device should be such that it would be accessible for maintenance during accident conditions.

The instrumentation should be energized from a high-reliability power source, not necessarily standby power, and should be backed up by batteries where momentary power interruption is not tolerable.

The out-of-service interval should be based on normal Technical Specifications out-of-service requirements for the system it serves, where applicable, or where specified by other requirements.

Since some instrumentation is less important to safety than other instrumentation, applying the same quality assurance measures to all instrumentation may not be necessary. The quality assurance requirements that are implemented should provide control over activities affecting quality to an extent consistent with the importance to safety of the instrumentation. These requirements should be determined and documented by personnel knowledgeable in the end use of the instrumentation.

The instrumentation signal may be displayed on an individual instrument or it may be processed for display on demand on a TV monitor or other appropriate means.

The method of display may be by dial, digital, TV monitor, or stripchart recorder indication. Effluent radioactivity monitors, area radiation monitors, and meteorology monitors should be recorded. Where direct and immediate trend or transient information is essential for operator information or action, the recording should be continuously available on dedicated recorders; otherwise, it may be continuously updated, stored in computer memory, and displayed on demand.

7.5.3.4.3 Design and Qualification Criteria - Category 3

The instrumentation should be high-quality commercial grade and should be selected to withstand the specified service environment.

The method of display may be by dial, digital, TV monitor, or stripchart recorder indication. Effluent radioactivity monitors, area radiation monitors, and meteorology monitors should be recorded. Where direct and immediate trend or transient information is essential for operator information or action, the recording should be continuously available on dedicated recorders; otherwise, it may be continuously updated, stored in computer memory, and displayed on demand.

7.5.3.4.4 Additional Criteria

In addition to the criteria of paragraphs 7.5.3.4.1 and 7.5.3.4.2, the following criteria should apply to Categories 1 and 2:

A. Any equipment that is used for either Category 1 or Category 2 should be designated as part of accident-monitoring instrumentation or systems operation and effluent-monitoring instrumentation. The transmission of signals from such equipment for other use should be through isolation devices that are designated as part of the monitoring instrumentation and that meet the provisions of this document.

B. The instruments designated as Types A, B, and C, and Categories 1 and 2 should be specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

7.5.3.4.5 Other Criteria

In addition to the above criteria, the following criteria should apply to Categories 1, 2, and 3:

A. Servicing, testing, and calibration programs should be specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing will be less than the normal time interval between generating station shutdowns, a capability for testing during power operation should be provided.

B. Whenever means for removing channels from service are included in the design, the design should facilitate administrative control of the access to such removal means.

C. The design should facilitate administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

D. The monitoring instrumentation design should minimize the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications potentially confusing to the operator. Human factors analysis should be used in determining type and location of displays.

E. The instrumentation should be designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

F. To the extent practicable, monitoring instrumentation inputs should be from sensors that directly measure the desired variables. An indirect measurement should be made only when it can be shown by analysis to provide unambiguous information.

G. To the extent practicable, the same instruments that are used for the normal operations of the plant should be used for accident monitoring to enable the operators to use, during accident situations, instruments with which they are most familiar. However, where the required range of monitoring instrumentation results in a loss of instrumentation sensitivity in the normal operating range, separate instruments should be used.

7.5.3.5 Description of Variables

7.5.3.5.1 Type A Variables (Plant Specific)

Type A variables are defined in paragraph 7.5.3.3.1. Key Type A variables provide the most direct measure of the information required. The key Type A variables are:

- RPV pressure.
- RPV water level.
- Drywell pressure (HNP-1 only).
- Drywell temperature in the vicinity of RPV level instrument reference leg.
- Suppression pool temperature.
- RHRSW flow.
- Diesel generators 1B (swing diesel), 1A, 1C, 2A, and 2C.
  - Output voltage.
  - Output current.
  - Output power.

- Battery voltage.

7.5.3.5.2 Type B Variables

Type B variables are defined in paragraph 7.5.3.3.2. The key variables are defined in the following paragraphs.

7.5.3.5.2.1 **Reactor Shutdown.** Operator verification that reactor shutdown has occurred may be made by observing one or more of the following indications:

- Control rod status lamps indicating each rod fully inserted.
- Control rod scram status lamps indicating open valves.
- Neutron monitoring power range channels and recorders downscale.

7.5.3.5.2.2 **RPV Water Level.** The total range of this variable is covered through use of two channels of multiple-level transmitters with overlapping ranges. These ranges are recorded in the main control room (MCR).

7.5.3.5.2.3 **RPV Pressure.** Two wide-range RPV pressure signals are transmitted from two independent pressure transmitters and are recorded in the MCR.

7.5.3.5.2.4 **RPV Isolation.** The operating staff may verify reactor isolation by observing the valve position lamps located with each valve's switch in the MCR. This information is available on the reactor/containment isolation mimic on MCR panels 1H11-P601 and 2H11-P601.

7.5.3.5.2.5 **Containment Pressure.** Two wide-range drywell pressure signals, two mid-range drywell pressure signals, and two narrow-range drywell pressure signals are transmitted from six separate pressure transmitters and are recorded in the MCR. Two mid-range torus pressure signals are transmitted from two separate pressure transmitters and are recorded in the MCR.

7.5.3.5.2.6 **Containment Temperature.** Drywell air temperatures are monitored at 15 locations that represent all quadrants and various elevations. These temperatures are recorded on multipoint recorders in the MCR.

7.5.3.5.2.7 Suppression Pool Level. Two wide-range and two narrow-range suppression pool level signals are transmitted from four separate differential pressure transmitters. The narrow-range signals are recorded in the MCR, while the wide-range signals are only indicated.

7.5.3.5.2.8 Containment Isolation. The operating staff may verify automatic containment isolation by observing the valve position lamps located with each valve's switch in the MCR. Selected valve information is also available on the reactor/containment isolation mimic on MCR panels 1H11-P601 and 2H11-P601.

7.5.3.5.3 Type C Variables

Type C variables are defined in paragraph 7.5.3.3.3. The key variables are defined in the following paragraphs.

7.5.3.5.3.1 Primary Containment Area Radiation. Two wide-range containment radiation signals are transmitted from two separate radiation detectors and are recorded in the MCR.

7.5.3.5.3.2 Containment and Drywell Hydrogen/Oxygen Concentration. The post-accident hydrogen and oxygen analyzing system consists of two redundant, separate subsystems, and each subsystem is capable of analyzing the hydrogen and oxygen content from the drywell or torus. Each hydrogen and oxygen analyzer channel is operated in parallel utilizing separate penetrations in the drywell and torus to monitor hydrogen and oxygen levels during and after a LOCA.

The hydrogen and oxygen analyzer mode is an ESF system. The redundant analyzer subsystems are contained in separate identical panels. The hydrogen analyzer is a dual-range device capable of measuring the volume-percent hydrogen. The oxygen analyzer is capable of measuring the volume-percent oxygen. Hydrogen and oxygen concentrations in the containment are continuously recorded in the MCR following a LOCA. This system is designed to be completely operable from two areas, at the local analyzer panel and the MCR. A hydrogen concentration of 2.4 volume percent, as measured by the analyzer, is annunciated in the MCR.

7.5.3.5.4 Type D Variables

Type D variables are defined in paragraph 7.5.3.3.4. The key variables are defined in the following paragraphs.

7.5.3.5.4.1 ADS Safety Relief Valves. The position of the ADS safety relief valves can be determined by the position indication lamps (indicates valve solenoid energized and tailpipe pressure switch actuated) in the MCR. Safety relief valve operation can also be verified from RPV pressure indications in the MCR.

7.5.3.5.4.2 <u>ECCS and RCIC System</u>. Operation of the ECCS and the RCIC system following an accident may be verified by observing the following indications:

- Flow indications for each ECCS.
- RCIC pump discharge flow.
- High-pressure coolant injection (HPCI) pump discharge flow.
- Low-pressure coolant injection (LPCI) flowrate.
- RHR flow in each loop.
- RHR heat exchanger outlet temperature.
- RHR service water flow in each loop.
- Condensate storage tank level.
- Core spray system flow.

These indications are shown on meters or recorders in the MCR. In addition, indirect and diverse methods are available to confirm LPCI and RHR containment spray by observing the individual loop-flow devices and valve lineups with indicating lights. RHR containment spray operation can also be inferred by observing containment pressure and temperature. LPCI performance can be evaluated by observing RPV water level and pressure.

7.5.3.5.4.3 <u>Suppression Pool Temperature</u>. The suppression pool bulk average water temperature is determined using the average of the operable temperature sensors located at various locations in the torus and is recorded in the MCR.

7.5.3.5.5 Type E Variables

Type E variables are defined in paragraph 7.5.3.3.5. The key variables are defined in the following paragraphs.

7.5.3.5.5.1 <u>Radiation Exposure Rate</u>. A number of radiation monitors that are defined in table 7.5-1 monitor the radiation levels within the HNP-1 and HNP-2 buildings. These monitors alert the MCR operators of activity levels in these areas and give local annunciation to alert operating staff of the hazards within the area. These variables are displayed or recorded in the MCR, except as noted in table 7.5-1.

7.5.3.5.5.2 **Meteorological Data.** HNP-1 has in-place meteorological instruments to measure wind speed, wind direction, and temperatures at various elevations to evaluate atmospheric stability. These instruments will be used to assess environmental conditions during and following any postulated accident in either HNP unit. These variables are displayed or recorded in the MCR, except as noted in table 7.5-1.

DOCUMENTS INCORPORATED BY REFERENCE INTO THE FSAR

Unit 1 and Unit 2 Technical Requirements Manual Table T7.0-1, Primary Containment Penetrations.

TABLE 7.5-1 (SHEET 1 OF 34)

HNP-1 AND HNP-2 EQUIPMENT VARIABLES

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Plant Specific:					
RPV Level	A	1	1, 2B21-LT N091A	1, 2B21-LIS N691A 1, 2B21-LI R604A	
	A	1	1, 2B21-LT N091B	1, 2B21-LIS N691B 1, 2B21-LI R604B	
	A	1	1, 2B21-LT N091C	1, 2B21-LIS N691C 1, 2B21- L/PR R623A	
	A	1	1, 2B21-LT N091D	1, 2B21-LIS N691D 1, 2B21- L/PR R623B	
RPV Pressure	A	1	1, 2B21-PT N090A	1, 2B21-PIS N690A 1, 2B21-L/PR R623A	
	A	1	1, 2B21-PT N090D	1, 2B21-PIS N690D 1, 2B21-L/PR R623B	
Drywell Pressure (HNP-1)	A	1	1T48-PT N023A	1T48-PR R608	
	A	1	1T48-PT N023B	1T48-PR R609	
RHRSW Flow	A	1	1, 2E11-FE N006A	1, 2E11-FI R602A	
	A	1	1, 2E11-FE N006B	1, 2E11-FI R602B	

TABLE 7.5-1 (SHEET 2 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Plant Specific: (continued)					
DG 1A Output Voltage (ESF Bus 1E)		1		1R11-VI R676	
DG 1B Output Voltage (ESF Bus 1F)	A	1		1R11-VI R677	
DG 1C Output Voltage (ESF Bus 1G)	A	1		1R11-VI R678	
DG 2A Output Voltage (ESF Bus 2E)	A	1		2R43-VI R904	
DG 1B Output Voltage (ESF Bus 2F)	A	1		2R43-VI R910	
DG 2C Output Voltage (ESF Bus 2G)	A	1		2R43-VI R918	
DG 1A Output Current	A	1		1R43-AI R653	
DG 1B Output Current	A	1		1R43-AI R654	
DG 1C Output Current	A	1		1R43-AI R655	
DG 2A Output Current	A	1		2R43-AI R622A	
DG 1B Output Current	A	1		2R43-AI R611	
DG 2C Output Current	A	1		2R43-AI R622C	
DG 1A Battery Voltage	A	1		1R43-VI R615A	
DG 1B Battery Voltage	A	1		1R43-VI R615B	
DG 1C Battery Voltage	A	1		1R43-VI R615C	
DG 2A Battery Voltage	A	1		2R43-VI R905	
DG 1B Battery Voltage	A	1		2R43-VI R919	
DG 2C Battery Voltage	A	1		2R43-VI R920	
DG 1A Output Power	A	1		1R43-WI R601A	
DG 1B Output Power	A	1		1R43-WI R601B	
DG 1C Output Power	A	1		1R43-WI R601C	
DG 2A Output Power	A	1		2R43-WI R615A	
DG 1B Output Power	A	1		2R43-WI R615B	
DG 2C Output Power	A	1		2R43-WI R615C	
DG 1A Output Power (Reactive)	A	1		1R43-WI R602A	
DG 1B Output Power (Reactive)	A	1		1R43-WI R602B	
DG 1C Output Power (Reactive)	A	1		1R43-WI R602C	

TABLE 7.5-1 (SHEET 3 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Plant Specific: (continued)					
DG 2A Output Power (Reactive)	A	1		2R43-WI R616A	
DG 1B Output Power (Reactive)	A	1		2R43-WI R616B	
DG 2C Output Power (Reactive)	A	1		2R43-WI R616C	
Drywell Temperature Near RPV Level Instrument	A	1	1T47-TE N001A	1T47-TR R611	
Reference Leg	A	1	1T47-TE N001B	1T47-TR R611	
	A	1	1T47-TE N009	1T47-TR R611	
	A	1	1T47-TE N001J	1T47-TR R612	
	A	1	1T47-TE N001K	1T47-TR R612	
	A	1	1T47-TE N003	1T47-TR R612	
	A	1	2T47-TE N001A	2T47-TR R626	
	A	1	2T47-TE N001B	2T47-TR R626	
	A	1	2T47-TE N009	2T47-TR R626	
	A	1	2T47-TE N001J	2T47-TR R627	
	A	1	2T47-TE N001K	2T47-TR R627	
	A	1	2T47-TE N003	2T47-TR R627	
Suppression Pool Temperature	A	1	Note 27	1, 2T48-TR R647	27
	A	1	1T48-TE N009A	1T47-TR R611	
	A	1	1T48-TE N009B	1T47-TR R612	
	A	1	1T48-TE N009C	1T47-TR R611	
	A	1	1T48-TE N009D	1T47-TR R612	
	A	1	2T48-TE N009A	2T47-TR R626	
	A	1	2T48-TE N009B	2T47-TR R627	
	A	1	2T48-TE N009C	2T47-TR R626	
	A	1	2T48-TE N009D	2T47-TR R627	
Coolant Level in Reactor	B	1	1, 2B21-LT N038A	NA	2, 31
	B	1	1, 2B21-LT N038B	NA	2, 31
	B	1	1, 2B21-LT N027	1, 2B21-LI R605	2
	B	1	1, 2B21-LT N085A	1, 2B21-LIS N685A 1, 2B21-L/PR R623A	2
	B	1	1, 2B21-LT N085B	1, 2B21-LIS N685B 1, 2B21-L/PR R623B	2
Coolant Level in Reactor (continued)	B	1	1, 2B21-LT N091A	1, 2B21-LIS N691A	2

TABLE 7.5-1 (SHEET 4 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				1, 2B21-LI R604A	
	B	1	1, 2B21-LT N091B	1, 2B21-LIS N691B	2
				1, 2B21-LI R604B	
	B	1	1, 2B21-LT N091C	1, 2B21-LIS N691C	2
				1, 2B21-L/PR R623A	
			1, 2B21-LT N091D	1, 2B21-LIS N691D	2
				1, 2B21-L/PR R623B	
	B	1	1, 2B21-LT N093A	1, 2B21-LIS N693A	2
	B	1	1, 2B21-LT N093B	1, 2B21-LIS N693B	2
	B	1	1, 2B21-LT N095A	1, 2B21-LIS N695A	2
	B	1	1, 2B21-LT N095B	1, 2B21-LIS N695B	2
RCS Pressure	B	1	1, 2B21-PT N090A	1, 2B21-PIS N690A 1, 2B21-L/PR R623A	
	B	1	1, 2B21-PT N090D	1, 2B21-PIS N690D 1, 2B21-L/PR R623B	
Neutron Flux-Source Range Monitor (SRM)	B	1	1, 2C51-RE N001A	1, 2C51-RIS K600A 1, 2C51-RI R600A 1, 2C51-RR R602	1, 18
	B	1	1, 2C51-RE N001B	1, 2C51-RIS K600B 1, 2C51-RI R600B 1, 2C51-RR R602	1, 18
	B	1	1, 2C51-RE N001C	1, 2C51-RIS K600C 1, 2C51-RI R600C 1, 2C51-RR R602	1, 18
	B	1	1, 2C51-RE N001D	1, 2C51-RIS K600D 1, 2C51-RI R600D 1, 2C51-RR R602	1, 18
Neutron Flux-Average Power Range Monitor (APRM)	B	1	Note 19	1, 2C51-RIS K615A 1, 2C51-RR R603A	1, 19
	B	1	Note 20	1, 2C51-RIS K615B 1, 2C51-RR R603B	1, 20
	B	1	Note 21	1, 2C51-RIS K615C 1, 2C51-RR R603C	1, 21
Neutron Flux-Average Power Range Monitor (APRM) (continued)	B	1	Note 22	1, 2C51-RIS K615D 1, 2C51-RR R603D	1, 22

TABLE 7.5-1 (SHEET 5 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Drywell Sump Level	B	1	1, 2G11-LT N074A	1, 2G11-LIS N001	3, 23
	B	1	1, 2G11-LT N074B	1, 2G11-LIS N002	3, 23
	B	1	1, 2G11-LT N075A	1, 2G11-LIS N008	3, 23
	B	1	1, 2G11-LT N075B	1, 2G11-LIS N009	3, 23
Drywell Pressure	B	1	1, 2T48-PT N020A	1, 2T48-L/PR R607A	
	B	1	1, 2T48-PT N020B	1, 2T48-L/PR R607B	
	B	1	1, 2T48-PT N003A	1, 2T48-P/RR R601A	
	B	1	1, 2T48-PT N003B	1, 2T48-P/RR R601B	
	B	1	1, 2T48-PT N023A	1, 2T48-PR R608	
	B	1	1, 2T48-PT N023B	1, 2T48-PR R609	
	B	1	2T48-PT N023A	2T48-PI R631A	
	B	1	2T48-PT N023B	2T48-PI R631B	
Primary Containment Pressure	B	1	2T48-PT N023A	2T48-PI R631A	
	B	1	2T48-PT N023B	2T48-PI R631B	
Primary Containment Pressure - Torus Pressure	B	1	1, 2T48-PT N008A	1, 2T48-PR R608	
	B	1	1, 2T48-PT N008B	1, 2T48-PR R609	
	B	1	2T48-PT N008A	2T48-PI R632A	
	B	1	2T48-PT N008B	2T48-PI R632B	
BWR Core Thermocouples	B	1	N/A	N/A	33
Primary Containment Isolation Valve (PCIV) Position (Excluding Check Valves)	B	1		1, 2B21-AOV F022A	34
	B	1		1, 2B21-AOV F022B	34
	B	1		1, 2B21-AOV F022C	34
	B	1		1, 2B21-AOV F022D	34
	B	1		1, 2B21-AOV F028A	34
	B	1		1, 2B21-AOV F028B	34
	B	1		1, 2B21-AOV F028C	34
	B	1		1, 2B21-AOV F028D	34
	B	1		1, 2B21-MOV F016	34
	B	1		1, 2B21-MOV F019	34

TABLE 7.5-1 (SHEET 6 OF 34)

HNP-1 AND HNP-2 EQUIPMENT VARIABLES

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
PCIV Position (Excluding Check Valves) (continued)	B	1		1, 2B31-AOV F019	34
	B	1		1, 2B31-AOV F020	34
	B	1		1C51-SV F3012	34
	B	1		1, 2C51-TIP J004A	34
	B	1		1, 2C51-TIP J004B	34
	B	1		1, 2C51-TIP J004C	34
	B	1		1, 2C51-TIP J004D	34
	B	1		1D11-SV F050	34
	B	1		1D11-SV F051	34
	B	1		1D11-SV F052	34
	B	1		1D11-SV F053	34
	B	1		2D11-AOV F050	34
	B	1		2D11-AOV F051	34
	B	1		2D11-AOV F052	34
	B	1		2D11-AOV F053	34
	B	1		2E11-AOV F041A	34
	B	1		2E11-AOV F041B	34
	B	1		2E11-AOV F041C	34
	B	1		2E11-AOV F041D	34
	B	1		1, 2E11-MOV F008	34
	B	1		1, 2E11-MOV F011A	34
	B	1		1, 2E11-MOV F011B	34
	B	1		1, 2E11-MOV F015A	34
	B	1		1, 2E11-MOV F015B	34
	B	1		1, 2E11-MOV F016A	34
	B	1		1, 2E11-MOV F016B	34
	B	1		1, 2E11-MOV F026A	34
	B	1		1, 2E11-MOV F026B	34
	B	1		1, 2E11-MOV F028A	34
	B	1		1, 2E11-MOV F028B	34

TABLE 7.5-1 (SHEET 7 OF 34)

HNP-1 AND HNP-2 EQUIPMENT VARIABLES

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
PCIV Position (Excluding Check Valves) (continued)	B	1		1, 2E21-MOV F015A	34
	B	1		1, 2E21-MOV F015B	34
	B	1		1, 2E41-MOV F002	34
	B	1		1, 2E41-MOV F003	34
	B	1		1, 2E41-MOV F012	34
	B	1		1, 2E41-MOV F042	34
	B	1		1, 2E41-MOV F104	34
	B	1		1, 2E41-MOV F111	34
	B	1		1, 2E51-MOV F007	34
	B	1		1, 2E51-MOV F008	34
	B	1		1, 2E51-MOV-F019	34
	B	1		1, 2E51-MOV F104	34
	B	1		1, 2E51-MOV F105	34
	B	1		1, 2G11-AOV F003	34
	B	1		1, 2G11-AOV F004	34
	B	1		1, 2G11-AOV F019	34
	B	1		1, 2G11-AOV F020	34
	B	1		1, 2G31-MOV F001	34
	B	1		1, 2G31-MOV F004	34
	B	1		2G51-AOV F011	34
	B	1		2G51-AOV F012	34
	B	1		1P33-SV F005	34
	B	1		1P33-SV F013	34
	B	1		2P33-AOV F005	34
	B	1		2P33-AOV F013	34
	B	1		1, 2P33-SV F605	34
	B	1		1, 2P33-AOV F002	34
	B	1		1, 2P33-AOV F003	34
	B	1		1, 2P33-AOV F004	34
	B	1		1, 2P33-AOV F006	34
	B	1		1, 2P33-AOV F007	34

TABLE 7.5-1 (SHEET 8 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
PCIV Position (Excluding Check Valves) (continued)	B	1		1, 2P33-AOV F010	34
	B	1		1, 2P33-AOV F011	34
	B	1		1, 2P33-AOV F012	34
	B	1		1, 2P33-AOV F014	34
	B	1		1, 2P33-AOV F015	34
	B	1		1, 2P70-AOV F002	34
	B	1		1, 2P70-AOV F003	34
	B	1		1, 2P70-SV F004	34
	B	1		1, 2P70-SV F005	34
	B	1		1, 2P70-SV F066	34
	B	1		1, 2P70-SV F067	34
	B	1		1T48-SV 118A	34
	B	1		1T48-SV 118B	34
	B	1		1T48-SV F338	34
	B	1		1T48-SV F339	34
	B	1		1T48-SV F340	34
	B	1		1T48-SV F341	34
	B	1		2T48-AOV F118A	34
	B	1		2T48-AOV F118B	34
	B	1		2T48-AOV F209	34
	B	1		2T48-AOV F210	34
	B	1		2T48-AOV F211	34
	B	1		2T48-AOV F212	34
	B	1		2T48-AOV F338	34
	B	1		2T48-AOV F339	34
	B	1		2T48-AOV F340	34
	B	1		2T48-AOV F341	34
	B	1		1, 2T48-AOV F103	34
	B	1		1, 2T48-AOV F104	34
	B	1		1, 2T48-AOV F307	34
	B	1		1, 2T48-AOV F308	34
	B	1		1, 2T48-AOV F309	34
	B	1		1, 2T48-AOV F318	34
	B	1		1, 2T48-AOV F319	34
	B	1		1, 2T48-AOV F320	34

TABLE 7.5-1 (SHEET 9 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
PCIV Position (Excluding Check Valves) (continued)	B	1		1, 2T48-AOV F324	34
	B	1		1, 2T48-AOV F326	34
	B	1		1, 2T48-AOV F332A	34
	B	1		1, 2T48-AOV F332B	34
	B	1		1, 2T48-AOV F333A	34
	B	1		1, 2T48-AOV F333B	34
	B	1		1, 2T48-AOVF334A	34
	B	1		1, 2T48-AOV F334B	34
	B	1		1, 2T48-AOV F335A	34
	B	1		1, 2T48-AOV F335B	34
RCS Soluble Boron Concentration (Sample)	B	3	Grab sample		
Control Rod Position	B	3	Note 17	Note 17	17
RCS Pressure	C	1	1, 2B21-PT N090A	1, 2B21-PIS N690A 1, 2B21-L/PR R623A	
	C	1	1, 2B21-PT N090D	1, 2B21-PIS N690D 1, 2B21-L/PR R623B	
Drywell Drain Sumps Level (Identified and Unidentified Leakage)	C	1	1, 2G11-LT N074A	1, 2G11-LIS N001	3, 23
	C	1	1, 2G11-LT N074B	1, 2G11-LIS N002	3, 23
	C	1	1, 2G11-LT N075A	1, 2G11-LIS N008	3, 23
	C	1	1, 2G11-LT N075B	1, 2G11-LIS N009	3, 23
Containment and Drywell Hydrogen Concentration	C	1	1, 2P33-P001A	1, 2P33-P601A 1, 2P33-H2I R604A	
	C	1	1, 2P33-P001A	1, 2P33-P601A 1, 2P33-H2R R601A	
	C	1	1, 2P33-P001B	1, 2P33-P601B 1, 2P33-H2I R604B	
	C	1	1, 2P33-P001B	1, 2P33-P601B 1, 2P33-H2R R601B	
Containment and Drywell Oxygen Concentration	C	1	1, 2P33-P001A	1, 2P33-P601A 1, 2P33-O2I R603A	

TABLE 7.5-1 (SHEET 10 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Containment and Drywell Oxygen Concentration (continued)	C	1	1, 2P33-P001A	1, 2P33-P601A 2P33-O2R R601A 1P33-O2R R602A	
	C	1	1, 2P33-P001B	1, 2P33-P601B 1, 2P33-O2I R603B	
	C	1	1, 2P33-P001B	1, 2P33-P601B 2P33-O2R R601B 1P33-O2R R602B	
Drywell Pressure	C	1	1, 2T48-PT N020A	1, 2T48-L/PR R607A	
	C	1	1, 2T48-PT N020B	1, 2T48-L/PR R607B	
	C	1	1, 2T48-PT N003A	1, 2T48-P/RR R601A	
	C	1	1, 2T48-PT N003B	1, 2T48-P/RR R601B	
	C	1	1, 2T48-PT N023A	1, 2T48-PR R608	
	C	1	1, 2T48-PT N023B	1, 2T48-PR R609	
	C	1	2T48-PT N023A	2T48-PI R631A	
	C	1	2T48-PT N023B	2T48-PI R631B	
Suppression Pool Water Level	C	1	1, 2T48-LT N021A	1, 2T48-L/PR R607A	
	C	1	1, 2T48-LT N021B	1, 2T48-L/PR R607B	
	C	1	1, 2T48-LT N010A	1, 2T48-LI R622A	
	C	1	1, 2T48-LT N010B	1, 2T48-LI R622B	
Primary Containment Pressure	C	1	1, 2T48-PT N003A	1, 2T48-P/RR R601A	
	C	1	1, 2T48-PT N003B	1, 2T48-P/RR R601B	
	C	1	2T48-PT N023A	2T48-PI R631A	
	C	1	2T48-PT N023B	2T48-PI R631B	
Primary Containment Pressure - Torus Pressure	C	1	1, 2T48-PT N008A	1, 2T48-PR R608	
	C	1	1, 2T48-PT N008B	1, 2T48-PR R609	
	C	1	2T48-PT N008A	2T48-PI R632A	
	C	1	2T48-PT N008B	2T48-PI R632B	
Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	C	1	N/A	N/A	4
BWR Core Thermocouples	C	1	N/A	N/A	33

TABLE 7.5-1 (SHEET 11 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Effluent Radioactivity:					
Noble Gases (Main Stack)	C	2	1D11-P001	1D11-RIS K600A 1D11-RR R600	14
	C	2	1D11-P001	1D11-RIS K600B 1D11-RR R600	14
Noble Gases (HNP-1 Reactor Bldg Vent Stack)	C	2	1D11-RE N020A	1D11-RIS K619A 1D11-RR R619	14
	C	2	1D11-RE N020B	1D11-RIS K619B 1D11-RR R619	14
	C	2	1D11-P007	1D11-RR R631	14
Noble Gases (HNP-2 Reactor Bldg Vent Stack)	C	2	2D11-RE N026A	2D11-RIS K636A 2D11-RR R619	14
	C	2	2D11-RE N026B	2D11-RIS K636B 2D11-RR R619	14
	C	2	2D11-P601	2D11-RR R631	14
Radiation Exposure Rate (HNP-1)	C	2	1D21-RE N002A	1D21-RIS K601A 1D21-RR R600	5
	C	2	1D21-RE N002B	1D21-RIS K601B 1D21-RR R600	5
	C	2	1D21-RE N002C	1D21-RIS K601C 1D21-RR R600	5
	C	2	1D21-RE N002D	1D21-RIS K601D 1D21-RR R600	5
	C	2	1D21-RE N002E	1D21-RIS K601E 1D21-RR R600	5
	C	2	1D21-RE N002F	1D21-RIS K601F 1D21-RR R600	5
	C	2	1D21-RE N002G	1D21-RIS K601G 1D21-RR R600	5
	C	2	1D21-RE N002H	1D21-RIS K601H 1D21-RR R600	5
	C	2	1D21-RE N002K	1D21-RIS K601K 1D21-RR R600	5
	C	2	1D21-RE N002L	1D21-RIS K602L	5

TABLE 7.5-1 (SHEET 12 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Radiation Exposure Rate (HNP-1) (continued)				1D21-RR R600	
	C	2	1D21-RE N002M	1D21-RIS K602M 1D21-RR R600	5
	C	2	1D21-RE N002N	1D21-RIS K602N 1D21-RR R600	5
	C	2	1D21-RE N002P	1D21-RIS K602P 1D21-RR R600	5
	C	2	1D21-RE N002R	1D21-RIS K602R 1D21-RR R600	5
	C	2	1D21-RE N002S	1D21-RIS K602S 1D21-RR R600	5
	C	2	1D21-RE N002T	1D21-RIS K602T 1D21-RR R600	5
	C	2	1D21-RE N002U	1D21-RIS K602U 1D21-RR R600	5
	C	2	1D21-RE N002V	1D21-RIS K601V 1D21-RR R600	5
	C	2	1D21-RE N002W	1D21-RIS K601W 1D21-RR R600	5
	C	2	1D21-RE N002X	1D21-RIS K601X 1D21-RR R600	5
	C	2	1D21-RE N002Y	1D21-RIS K601Y 1D21-RR R600	5
	C	2	1D21-RE N017	1D21-RIS K617	5
Radiation Exposure Rate (HNP-2)	C	2	2D21-RE N001D	2D21-RIS K600D 2D21-RR R600A	5
	C	2	2D21-RE N002A	2D21-RIS K601A 2D21-RR R600A	5
	C	2	2D21-RE N002B	2D21-RIS K601B 2D21-RR R600A	5
	C	2	2D21-RE N002C	2D21-RIS K601C 2D21-RR R600A	5
	C	2	2D21-RE-N002D	2D21-RIS-K601D 2D21-RR R600A	5
	C	2	2D21-RE N002E	2D21-RIS K601E	5

TABLE 7.5-1 (SHEET 13 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Radiation Exposure Rate (HNP-2) (continued)				2D21-RR R600A	
	C	2	2D21-RE N002F	2D21-RIS K601F 2D21-RR R600A	5
	C	2	2D21-RE N002G	2D21-RIS K601G 2D21-RR R600A	5
	C	2	2D21-RE N002H	2D21-RIS K601H 2D21-RR R600A	5
	C	2	2D21-RE N002L	2D21-RIS K601L 2D21-RR R600A	5
	C	2	2D21-RE N002M	2D21-RIS K601M 2D21-RR R600A	5
	C	2	2D21-RE N002N	2D21-RIS K601N 2D21-RR R600A	5
	C	2	2D21-RE N002P	2D21-RIS K601P 2D21-RR R600A	5
	C	2	2D21-RE N002R	2D21-RIS K601R 2D21-RR R600A	5
	C	2	2D21-RE N002S	2D21-RIS K601S 2D21-RR R600A	5
	C	2	2D21-RE N002T	2D21-RIS K601T 2D21-RR R600A	5
	C	2	2D21-RE N002U	2D21-RIS K601U 2D21-RR R600A	5
	C	2	2D21-RE N002V	2D21-RIS K601V 2D21-RR R600A	5
	C	2	2D21-RE N002W	2D21-RIS K601W 2D21-RR R600A	5
	C	2	2D21-RE N002X	2D21-RIS K601X 2D21-RR R600A	5
	C	2	2D21-RE N002Y	2D21-RIS K601Y 2D21-RR R600A	5
	C	2	2D21-RE N012K	2D21-RIS K611K 2D21-RR R600A	5
	C	2	2D21-RE N012L	2D21-RIS K611L 2D21-RR R600A	5
Primary Containment Area Radiation	C	3	1, 2D11-RE N003A	1, 2D11-RIS K621A	

TABLE 7.5-1 (SHEET 14 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
	C	3	1, 2D11-RE N003B	1, 2T48-P/RR R601A 1, 2D11-RIS K621B 1, 2T48-P/RR R601B	
Analysis of Primary Coolant (Gamma Spectrum)	C	3	N/A	N/A	
Containment Effluent Radioactivity - Noble Gases (from identified release points including SGTS Vent)	C	3	N/A	N/A	
Primary System SRV Positions, Including ADS or Flow-Through or Pressure in Valve Lines	D	2	1B21-PS N301A	1B21C-DS3A	8
	D	2	1B21-PS N301B	1B21C-DS3K	8
	D	2	1B21-PS N301C	1B21C-DS3C	8
	D	2	1B21-PS N301D	1B21C-DS3L	8
	D	2	1B21-PS N301E	1B21C-DS3H	8
	D	2	1B21-PS N301F	1B21C-DS3F	8
	D	2	1B21-PS N301G	1B21C-DS3G	8
	D	2	1B21-PS N301H	1B21C-DS3E	8
	D	2	1B21-PS N301J	1B21C-DS3J	8
	D	2	1B21-PS N301K	1B21C-DS3B	8
	D	2	1B21-PS N301L	1B21C-DS3D	8
	D	2	2B21-PS N302A	2B21C-DS3A	8
	D	2	2B21-PS N302B	2B21C-DS3G	8
	D	2	2B21-PS N301C	2B21C-DS3C	8
	D	2	2B21-PS N301D	2B21C-DS3K	8
	D	2	2B21-PS N302E	2B21C-DS3B	8
	D	2	2B21-PS N302F	2B21C-DS3F	8
	D	2	2B21-PS N301G	2B21C-DS3M	8
	D	2	2B21-PS N301H	2B21C-DS3H	8
	D	2	2B21-PS N302K	2B21C-DS3D	8
	D	2	2B21-PS N301L	2B21C-DS3E	8
	D	2	2B21-PS N301M	2B21C-DS3L	8
Standby Liquid Control System (SLCS) Storage Tank Level	D	2	1, 2C41-LT N001	1, 2C41-LI R601	10
SLCS Flow	D	2	1, 2C41-PT N004	1, 2C41-PI R600	9
LPCI Flow	D	2	1, 2E11-FE N014A	1, 2E11-FI R603A 1, 2E11-FR R608A	
LPCI Flow (continued)	D	2	1, 2E11-FE N014B	1, 2E11-FI R603B 1, 2E11-FR R608B	

TABLE 7.5-1 (SHEET 15 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
RHR System Flow	D	2	1, 2E11-FE N014A	1, 2E11-FI R603A 1, 2E11-FR R608A	
	D	2	1, 2E11-FE N014B	1, 2E11-FI R603B 1, 2E11-FI R608B	
Core Spray System Flow	D	2	1, 2E21-FE N002A 1, 2E21-FE N002B	1, 2E21-FI R601A 1, 2E21-FI R601B	
HPCI System Flow	D	2	1, 2E41-FE N007	1, 2E41-FIC R612	
RCIC Flow	D	2	1, 2E51-FE N001	1, 2E51-FIC R612	
Cooling Water Flow to ESF System Components	D D	2 2	1P41-PT N502 1P41-PT N511	1P41-PI R900 1P41-PI R910	12 12
	D D	2 2	2P41-PT N303A 2P41-PT N303B	2P41-PI R601A 2P41-PI R601B	12 12
Cooling Water Temperature to ESF System Components	D	2	1, 2P41-TE N001 1, 2P41-TE N002 1, 2P41-TE N003A 1, 2P41-TE N003B 1. 2P41-TE N003C 1, 2P41-TE N003D 1, 2P41-TE N005 1, 2P41-TE N006	1, 2P41-TI R300 1, 2P41-TI R301 1, 2P41-TI R302A 1, 2P41-TI R302B 1, 2P41-TI R302C 1, 2P41-TI R302D 1, 2P41-TI R304 1, 2P41-TI R305	11, 23 11, 23 11, 23 11, 23 11, 23 11, 23 11, 23 11, 23
			N/A N/A N/A N/A N/A N/A	1P41-TI R517 1P41-TI R518 1P41-TI R519 1P41-TI R520 1P41-TI R521 1P41-TI R522	11, 23 11, 23 11, 23 11, 23 11, 23 11, 23
Status of Standby Power:					
DG 1A - 4 kV ESF Bus 1E Voltage	D	2		1R11-VI R676	

TABLE 7.5-1 (SHEET 16 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
DG 1B - 4 kV ESF Bus 1F Voltage	D	2		1R11-VI R677	
DG 1C - 4 kV ESF Bus 1G Voltage	D	2		1R11-VI R678	
DG 2A - 4 kV ESF Bus 2E Voltage	D	2		2R43-VI R904	
DG 1B - 4 kV ESF Bus 2F Voltage	D	2		2R43-VI R910	
DG 2C - 4 kV ESF Bus 2G Voltage	D	2		2R43-VI R918	
600 V-ac ESF Bus 1C Voltage	D	2		1R11-VI R673 1R11-VI R674	
600 V-ac ESF Bus 1C Ammeter	D	2		1R11-AI R659	
600 V-ac ESF Bus 2C Ammeter	D	2		2R71-VI R909	
600 V-ac ESF Bus 2C Voltage	D	2		2R71-AI R910	
600 V-ac ESF Bus 2D Ammeter	D	2		2R71-VI R916	
600 V-ac ESF Bus 2D Voltage	D	2		2R71-AI R917	
DG 1A Output Current	D	2		1R43-AI R653	
DG 1B Output Current	D	2		1R43-AI R654	
DG 1C Output Current	D	2		1R43-AI R655	
DG 2A Output Current	D	2		2R43-AI R622A	
DG 1B Output Current	D	2		2R43-AI R611	
DG 2C Output Current	D	2		2R43-AI R622C	
DG 1A Battery Voltage	D	2		1R43-VI R615A	
DG 1B Battery Voltage	D	2		1R43-VI R615B	
DG 1C Battery Voltage	D	2		1R43-VI R615C	
DG 2A Battery Voltage	D	2		2R43-VI R905	
DG 1B Battery Voltage	D	2		2R43-VI R919	
DG 2C Battery Voltage	D	2		2R43-VI R920	
DG 2A Output Power	D	2		2R43-WI R615A	
DG 1B Output Power	D	2		2R43-WI R615B	
DG 2C Output Power	D	2		2R43-WI R615C	
Status of Standby power (continued)					
DG 2A Output Power (Reactive)	D	2		2R43-WI R616A	
DG 1B Output Power (Reactive)	D	2		2R43-WI R616B	
DG 2C Output Power (Reactive)	D	2		2R43-WI R616C	

TABLE 7.5-1 (SHEET 17 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
24/48 V Charger 1A P Pole Ammeter	D	2		1R41-AI R602A	
24/48 V Charger 1A N Pole Ammeter	D	2		1R41-AI R602B	
24/48 V Charger 1B P Pole Ammeter	D	2		1R41-AI R605A	
24/48 V Charger 1B N Pole Ammeter	D	2		1R41-AI R605B	
125/250 V-dc Battery 1A R42-S001A P Pole Ammeter	D	2		1R42-AI R601A	
125/250 V-dc Battery 1A R42-S001A PN Pole Ammeter	D	2		1R42-AI R601B	
125/250 V-dc Battery 1A R42-S001A N Pole Ammeter	D	2		1R42-AI R601C	
125/250 V-dc Charger 1A R42-S001B P Pole Ammeter	D	2		1R42-AI R602A	
125/250 V-dc Charger 1A R42-S001B P Pole Ammeter	D	2		1R42-AI R602B	
125/250 V-dc Battery 1B R42-S001B P Pole Ammeter	D	2		1R42-AI R604A	
125/250 V-dc Battery 1B R42-S001B PN Pole Ammeter	D	2		1R42-AI R604B	
125/250 V-dc Charger 1B R42-S001B P Pole Ammeter	D	2		1R42-AI R605A	
125/250 V-dc Charger 1B R42-S001B P Pole Ammeter	D	2		1R42-AI R605B	
24/48 V Charger 2A P Pole Ammeter	D	2		2R41-AI R602A	
24/48 V Charger 2A N Pole Ammeter	D	2		2R41-AI R602B	
24/48 V Charger 2B P Pole Ammeter	D	2		2R41-AI R605A	
24/48 V Charger 2B N Pole Ammeter	D	2		2R41-AI R605B	
125/250 V-dc Charger 2A P Pole Ammeter	D	2		2R42-AI R602A	
125/250 V-dc Charger 2A N Pole Ammeter	D	2		2R42-AI R602B	
125/250 V-dc Charger 2B P Pole Ammeter	D	2		2R42-AI R605A	
125/250 V-dc Charger 2B N Pole Ammeter	D	2		2R42-AI R605B	
Emergency Ventilation Damper Position	D	2		1, 2T41-AOV F003A	
				1, 2T41-AOV F003B	
				1, 2T41-AOV F011A	
				1, 2T41-AOV F011B	
				1, 2T41-AOV F023A	
				1, 2T41-AOV F023B	
				1T41-AOV F032A	
				1T41-AOV F032B	
Emergency Ventilation Damper Position (continued)				1T41-AOV F040A	
				1T41-AOV F040B	
				1T41-AOV F043A	
				1T41-AOV F043B	
				1, 2T41-AOV F044A	

TABLE 7.5-1 (SHEET 18 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				1, 2T41-AOV F044B	
				1, 2T46-AOV F001A	
				1, 2T46-AOV F001B	
				1, 2T46-AOV F002A	
				1, 2T46-AOV F002B	
				1, 2T46-AOV F003A	
				1, 2T46-AOV F003B	
				1T46-AOV F004A	
				1T46-AOV F004B	
Suppression Pool Water Temperature	D	2	Note 27	1, 2T48-TR R647	27
	D	2	1T48-TE N009A	1T47-TR R611	
	D	2	1T48-TE N009B	1T47-TR R612	
	D	2	1T48-TE N009C	1T47-TR R611	
	D	2	1T48-TE N009D	1T47-TR R612	
	D	2	2T48-TE N009A	2T47-TR R626	
	D	2	2T48-TE N009B	2T47-TR R627	
	D	2	2T48-TE N009C	2T47-TR R626	
	D	2	2T48-TE N009D	2T47-TR R627	
Drywell Atmosphere Temperature	D	2	Note 25	1T47-TR R611	25
	D	2	Note 26	1T47-TR R612	26
	D	2	Note 25	2T47-TR R626	25, 36
	D	2	Note 26	2T47-TR R627	26, 36
RHR Heat Exchanger Outlet Temperature	D	2	1E11-TE-N027A	1T47-TR R611	
	D	2	1E11-TE N027B	1T47-TR R612	
	D	2	2E11-TE N027A	2T47-TR R626	
	D	2	2E11-TE N027B	2T47-TR R627	
Drywell Pressure	D	2	1, 2T48-PT N020A	1, 2T48-L/PR R607A	
	D	2	1, 2T48-PT N020B	1, 2T48-L/PR R607B	
	D	2	1, 2T48-PT N023A	1, 2T48-PR R608	
	D	2	1, 2T48-PT N023B	1, 2T48-PR R609	
	D	2	2T48-PT N023A	2T48-PI R631A	

TABLE 7.5-1 (SHEET 19 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
	D	2	2T48-PT N023B	2T48-PI R631B	
Suppression Chamber Spray Flow	D	2	N/A	N/A	6, 29
Suppression Pool Water Level	D	2	N/A	N/A	30
Drywell Spray Flow	D	2	N/A	N/A	6, 29
MSIV Leakage Control System (LCS) pressure (HNP-1)	D	2	N/A	N/A	35
Isolation Condenser System Shell-Side Water Level	D	2	N/A	N/A	29
Isolation Condenser System Valve Position	D	2	N/A	N/A	29
Status of Standby Power and Other Energy Sources Important to Safety (Hydraulic, Pneumatic)	D	2	N/A	N/A	
Main Feedwater Flow	D	3	1, 2C32-FE N001A	1, 2C32-FI R604A	
	D	3	1, 2C32-FE N001B	1, 2C32-FI R604B	
High Radioactivity Liquid Tank Level	D	3	1G11-LT N020	1G11-LRS R007	24
			1G11-LT N035	1G11-LRS R025	24
	D	3	2G11-LT N020	2G11-LR R117	24
			2G11-LT N035	2G11-LR R122	24
Condensate Storage Tank Level	D	3	1P11-LT N001	1P11-LI R900	
	D	3	2P11-LT N001	2P11-LI R601	
Primary System SRV Position (Secondary indication)	D	3	Note 16	1, 2 B21-TR R614	16
Primary Containment Area Radiation - High Range	E	1	1, 2D11-RE N003A	1, 2D11-RIS K621A	
				1, 2T48-P/RR R601A	
	E	1	1, 2D11-RE N003B	1, 2D11-RIS K621B	
Reactor Bldg or Secondary Containment Area Radiation (HNP-1)	E	2	1D21-RE N002A	1D21-RIS K601A	5
				1D21-RR R600	
	E	2	1D21-RE N002B	1D21-RIS K601B	5

TABLE 7.5-1 (SHEET 20 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				1D21-RR R600	
	E	2	1D21-RE N002C	1D21-RIS K601C 1D21-RR R600	5
	E	2	1D21-RE-N002D	1D21-RIS-K601D 1D21-RR R600	5
	E	2	1D21-RE N002E	1D21-RIS K601E 1D21-RR R600	5
	E	2	1D21-RE N002F	1D21-RIS K601F 1D21-RR R600	5
	E	2	1D21-RE N002G	1D21-RIS K601G 1D21-RR R600	5
	E	2	1D21-RE N002H	1D21-RIS K601H 1D21-RR R600	5
	E	2	1D21-RE N002K	1D21-RIS K601K 1D21-RR R600	5
	E	2	1D21-RE N002L	1D21-RIS K602L 1D21-RR R600	5
	E	2	1D21-RE N002M	1D21-RIS K602M 1D21-RR R600	5
	E	2	1D21-RE N002N	1D21-RIS K602N 1D21-RR R600	5
	E	2	1D21-RE N002P	1D21-RIS K602P 1D21-RR R600	5
	E	2	1D21-RE N002R	1D21-RIS K602R 1D21-RR R600	5
	E	2	1D21-RE N002S	1D21-RIS K602S 1D21-RR R600	5
	E	2	1D21-RE N002T	1D21-RIS K602T 1D21-RR R600	5
	E	2	1D21-RE N002U	1D21-RIS K602U 1D21-RR R600	5
	E	2	1D21-RE N002V	1D21-RIS K601V 1D21-RR R600	5
	E	2	1D21-RE N002W	1D21-RIS K601W 1D21-RR R600	5
	E	2	1D21-RE N002X	1D21-RIS K601X 1D21-RR R600	5

TABLE 7.5-1 (SHEET 21 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
	E	2	1D21-RE N002Y	1D21-RIS K601Y 1D21 RR R600	5
Reactor Bldg or Secondary Containment Area Radiation (HNP-2)	E	2	1D21-RE N017	1D21-RIS K617	5
	E	2	2D21-RE N001D	2D21-RIS K600D 2D21-RR R600A	5
	E	2	2D21-RE N002A	2D21-RIS K601A 2D21-RR R600A	5
	E	2	2D21-RE N002B	2D21-RIS K601B 2D21-RR R600A	5
	E	2	2D21-RE N002C	2D21-RIS K601C 2D21-RR R600A	5
	E	2	2D21-RE-N002D	2D21-RIS-K601D 2D21-RR R600A	5
	E	2	2D21-RE N002E	2D21-RIS K601E 2D21-RR R600A	5
	E	2	2D21-RE N002F	2D21-RIS K601F 2D21-RR R600A	5
	E	2	2D21-RE N002G	2D21-RIS K601G 2D21-RR R600A	5
	E	2	2D21-RE N002H	2D21-RIS K601H 2D21-RR R600A	5
	E	2	2D21-RE N002L	2D21-RIS K601L 2D21-RR R600A	5
	E	2	2D21-RE N002M	2D21-RIS K601M 2D21-RR R600A	5
	E	2	2D21-RE N002N	2D21-RIS K601N 2D21-RR R600A	5
	E	2	2D21-RE N002P	2D21-RIS K601P 2D21-RR R600A	5
Reactor Bldg or Secondary Containment Area Radiation (HNP-2) (continued)	E	2	2D21-RE N002R	2D21-RIS K601R 2D21-RR R600A	5
	E	2	2D21-RE N002S	2D21-RIS K601S 2D21-RR R600A	5
	E	2	2D21-RE N002T	2D21-RIS K601T 2D21-RR R600A	5
	E	2	2D21-RE N002U	2D21-RIS K601U 2D21-RR R600A	5
	E	2	2D21-RE N002V	2D21-RIS K601V	5

TABLE 7.5-1 (SHEET 22 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				2D21-RR R600A	
	E	2	2D21-RE N002W	2D21-RIS K601W 2D21-RR R600A	5
	E	2	2D21-RE N002X	2D21-RIS K601X 2D21-RR R600A	5
	E	2	2D21-RE N002Y	2D21-RIS K601Y 2D21-RR R600A	5
	E	2	2D21-RE N012K	2D21-RIS K611K 2D21-RR R600A	5
	E	2	2D21-RE N012L	2D21-RIS K611L 2D21-RR R600A	5
Common Plant Vent or Multipurpose Vent Discharge (if containment purge is included)	E	2	1D11-P001	1D11-RIS K600A 1D11-RR R600	14
	E	2	1D11-P001	1D11-RIS K600B 1D11-RR R600	14
	E	2	1D11-RE N020A	1D11-RIS K619A 1D11-RR R619	14
	E	2	1D11-RE N020B	1D11-RIS K619B 1D11-RR R619	14
	E	2	1D11-P007	1D11-RR R631	14
	E	2	2D11-RE N026A	2D11-RIS K636A 2D11-RR R619	14
	E	2	2D11-RE N026B	2D11-RIS K636B 2D11-RR R619	14
	E	2	2D11-P601	2D11-RR R631	14
Radiation Exposure Rate (HNP-1)	E	2	1D21-RE N001A	1D21-RIS K600A 1D21-RR R600	13
	E	2	1D21-RE N001B	1D21-RIS K600B 1D21-RR R600	13
	E	2	1D21-RE N001C	1D21-RIS K600C 1D21-RR R600	13
	E	2	1D21-RE N001D	1D21-RIS K600D 1D21-RR R600	13
	E	2	1D21-RE N001E	1D21-RIS K600E	13

TABLE 7.5-1 (SHEET 23 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				1D21-RR R600	
	E	2	1D21-RE N001F	1D21-RIS K600F	13
				1D21-RR R600	
	E	2	1D21-RE N001G	1D21-RIS K600G	13
				1D21-RR R600	
	E	2	1D21-RE N001H	1D21-RIS K600H	13
				1D21-RR R600	
	E	2	1D21-RE N002A	1D21-RIS K601A	13
				1D21-RR R600	
	E	2	1D21-RE N002B	1D21-RIS K601B	13
				1D21-RR R600	
	E	2	1D21-RE N002C	1D21-RIS K601C	13
				1D21-RR R600	
	E	2	1D21-RE N002D	1D21-RIS K601D	13
				1D21-RR R600	
	E	2	1D21-RE N002E	1D21-RIS K601E	13
				1D21-RR R600	
	E	2	1D21-RE N002F	1D21-RIS K601F	13
				1D21-RR R600	
	E	2	1D21-RE N002G	1D21-RIS K601G	13
				1D21-RR R600	
	E	2	1D21-RE N002H	1D21-RIS K601H	13
				1D21-RR R600	
	E	2	1D21-RE N002K	1D21-RIS K601K	13
				1D21-RR R600	
	E	2	1D21-RE N002L	1D21-RIS K602L	13
				1D21-RR R600	
Radiation Exposure Rate (HNP-1) (continued)	E	2	1D21-RE N002M	1D21-RIS K602M	13
				1D21-RR R600	
	E	2	1D21-RE N002N	1D21-RIS K602N	13
				1D21-RR R600	
	E	2	1D21-RE N002R	1D21-RIS K602R	13
				1D21-RR R600	
	E	2	1D21-RE N002S	1D21-RIS K602S	13
				1D21-RR R600	
	E	2	1D21-RE N002T	1D21-RIS K602T	13

TABLE 7.5-1 (SHEET 24 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				1D21-RR R600	
	E	2	1D21-RE N002U	1D21-RIS K602U	13
				1D21-RR R600	
	E	2	1D21-RE N002V	1D21-RIS K601V	13
				1D21-RR R600	
	E	2	1D21-RE N002W	1D21-RIS K601W	13
				1D21-RR R600	
	E	2	1D21-RE N002X	1D21-RIS K601X	13
				1D21-RR R600	
	E	2	1D21-RE N002Y	1D21-RIS K601Y	13
				1D21-RR R600	
	E	2	1D21-RE N002Z	1D21-RIS K601Z	13
				1D21-RR R600	
	E	2	1D21-RE N010	1D21-RIS K610	13
	E	2	1D21-RE N011	1D21-RIS K611	13
	E	2	1D21-RE N012	1D21-RIS K612	13
	E	2	1D21-RE N013	1D21-RIS K613	13
	E	2	1D21-RE N014	1D21-RIS K614	13
	E	2	1D21-RE N015	1D21-RIS K615	13
	E	2	1D21-RE N016	1D21-RIS K616	13
	E	2	1D21-RE N017	1D21-RIS K617	13
Radiation Exposure Rate (HNP-2)	E	2	2D21-RE N001A	2D21-RIS K600A	13
				2D21-RR R600A	
	E	2	2D21-RE N001B	2D21-RIS K600B	13
				2D21-RR R600A	
	E	2	2D21-RE N001C	2D21-RIS K600C	13
				2D21-RR R600A	
	E	2	2D21-RE N001D	2D21-RIS K600D	13
Radiation Exposure Rate (HNP-2) (continued)				2D21-RR R600A	
	E	2	2D21-RE N001E	2D21-RIS K600E	13
				2D21-RR R600A	
	E	2	2D21-RE N001F	2D21-RIS K600F	13
				2D21-RR R600A	
	E	2	2D21-RE N001G	2D21-RIS K600G	13
				2D21-RR R600A	
	E	2	2D21-RE N001H	2D21-RIS K600H	13
				2D21-RR R600A	
	E	2	2D21-RE N001K	2D21-RIS K600K	13

TABLE 7.5-1 (SHEET 25 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Radiation Exposure Rate (HNP-2) (continued)	E	2	2D21-RE N002A	2D21-RIS K601A 2D21-RR R600A	13
	E	2	2D21-RE N002B	2D21-RIS K601B 2D21-RR R600A	13
	E	2	2D21-RE N002C	2D21-RIS K601C 2D21-RR R600A	13
	E	2	2D21-RE N002D	2D21-RIS K601D 2D21-RR R600A	13
	E	2	2D21-RE N002E	2D21-RIS K601E 2D21-RR R600A	13
	E	2	2D21-RE N002F	2D21-RIS K601F 2D21-RR R600A	13
	E	2	2D21-RE N002G	2D21-RIS K601G 2D21-RR R600A	13
	E	2	2D21-RE N002H	2D21-RIS K601H 2D21-RR R600A	13
	E	2	2D21-RE N002K	2D21-RIS K601K 2D21-RR R600A	13
	E	2	2D21-RE N002L	2D21-RIS K601L 2D21-RR R600A	13
	E	2	2D21-RE N002M	2D21-RIS K601M 2D21-RR R600A	13
	E	2	2D21-RE N002N	2D21-RIS K601N 2D21-RR R600A	13
	E	2	2D21-RE N002P	2D21-RIS K601P 2D21-RR R600A	13
	E	2	2D21-RE N002R	2D21-RIS K601R 2D21-RR R600A	13
	E	2	2D21-RE N002S	2D21-RIS K601S 2D21-RR R600A	13
	E	2	2D21-RE N002T	2D21-RIS K601T 2D21-RR R600A	13
	E	2	2D21-RE N002U	2D21-RIS K601U 2D21-RR R600A	13
	E	2	2D21-RE N002V	2D21-RIS K601V 2D21-RR R600A	13
	E	2	2D21-RE N002W	2D21-RIS K601W 2D21-RR R600A	13

TABLE 7.5-1 (SHEET 26 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
	E	2	2D21-RE N002X	2D21-RIS K601X 2D21-RR R600A	13
	E	2	2D21-RE N002Y	2D21-RIS K601Y 2D21-RR R600A	13
	E	2	2D21-RE N002Z	2D21-RIS K601Z	13
	E	2	2D21-RE N012A	2D21-RIS K611A	13
	E	2	2D21-RE N012B	2D21-RIS K611B	13
	E	2	2D21-RE N012C	2D21-RIS K611C	13
	E	2	2D21-RE N012D	2D21-RIS K611D	13
	E	2	2D21-RE N012E	2D21-RIS K611E	13
	E	2	2D21-RE N012F	2D21-RIS K611F	13
	E	2	2D21-RE N012G	2D21-RIS K611G	13
	E	2	2D21-RE N012H	2D21-RIS K611H	13
	E	2	2D21-RE N012K	2D21-RIS K611K 2D21-RR R600A	13
	E	2	2D21-RE N012L	2D21-RIS K611L 2D21-RR R600A	13
Containment Air - Hydrogen Content	E	3	Grab Sample		
Containment Air - Oxygen Content	E	3	Grab Sample		
Wind Direction	E	3	1Y33-POT N006	1Y33-S/ZR/XR R601	
	E	3	1Y33-POT N005	1Y33-S/ZR/XR R602	
	E	3	1Y33-POT N004	1Y33-S/ZR/XR R603	
	E	3	1Y33-POT N048	1Y33-S/ZR/XR/DTR/UR R604	
Wind Speed	E	3	1Y33-FT N003	1Y33-S/ZR/XR R601	
	E	3	1Y33-FT N002	1Y33-S/ZR/XR R602	
	E	3	1Y33-FT N001	1Y33-S/ZR/XR R603	
	E	3	1Y33-FT N047	1Y33-S/ZRXR/DTR/UR R604	
Estimation of Atmospheric Stability	E	3	1Y33-TE N051	1Y33-S/ZR/XR/DTR/UR	

TABLE 7.5-1 (SHEET 27 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
				R604	32
	E	3	1Y33-TE N050	1Y33-S/ZR/XR/DTR/UR R604	32
	E	3	1Y33-TE N014	1Y33-UR/DTR/QR R606	32
	E	3	1Y33-TE N015	1Y33-UR/DTR/QR R606	32
	E	3	1Y33-FS N037	1Y33-FIS N604	32
	E	3	1Y33-FS N036	1Y33-FIS N604	32
	E	3	1Y33-FS N035	1Y33-FIS N604	32
	E	3	1Y33-FS N059	1Y33-FIS N605	32
	E	3	1Y33-FS N058	1Y33-FIS N605	32
	E	3	1Y33-ME N021	1Y33-UR/DTR/QR R606	32
	E	3	1Y33-TE N013	1Y33-UR/DTR/QR R606	32
	E	3	1Y33-ME N020	1Y33-UR/DTR/QR R606	32
	E	3	1Y33-POQ N031	1Y33-S/ZR/XR R601	32
	E	3	1Y33-POQ N030	1Y33-S/ZR/XR R602	32
	E	3	1Y33-POQ N029	1Y33-S/ZR/XR R603	32
	E	3	1Y33-POQ N055	1Y33-S/ZR/XR/DTR/UR R604	32
Particulates and Halogens-All Identified Plant Release Points	E	3	1D11-P006	N/A	
	E	3	2D11-P005	N/A	
Sampling with Onsite Analysis Capability Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability)	E	3	N/A	N/A	7
Plant and Environs Radiation (portable instrumentation)	E	3	N/A	N/A	7
Plant and Environs Radioactivity (portable instrumentation)	E	3	N/A	N/A	7
Radiation Exposure Meters (continuous indication at fixed locations)	E	3	N/A	N/A	7, 28
Primary Coolant and Sump:					
Gross Activity	E	3	2P33-RE N070	2P33-P210 2P33-P211	7, 15
Gamma Spectrum	E	3	2P33-RE N070	2P33-P210 2P33-P211	7, 15
Boron Content	E	3	2P33-BOE N054	2P33-BIT R078 2P33-P211	7, 15

TABLE 7.5-1 (SHEET 28 OF 34)

Measured Variable	RG 1.97 Type	RG 1.97 Cat	Sensor MPL No.	Receiver MPL No.	Notes
Chloride Content	E	3	Grab Sample		7, 15
Dissolved Hydrogen or Total Gas	E	3	2P33-H2E N051	2P33-H2IT N073 2P33-P211	7, 15
pH	E	3	Grab Sample		7, 15
Containment Air - Gamma Spectrum	E	3	2P33-RE N070	2P33-P210 2P33-P211	7, 15

TABLE 7.5-1 (SHEET 29 OF 34)

NOTES:

1. HNP-1 and HNP-2 neutron flux monitor systems are not Category 1. The Boiling Water Reactor Owners Group (BWROG) appealed issue of upgrading this system to Category 1. HNP has committed to follow industry development of this equipment and evaluate the installation of improved instrumentation when it becomes available.

2. HNP-1 and HNP-2 take credit for meeting the range requirements for coolant level in the reactor by use of multiple scales to envelop the range requirements. Four ranges of levels used are:

   - Normal operating range (0 to 60 in. water column (wc)).
   - Emergency system range (-150 in. to 60 in. wc).
   - Shutdown vessel flooding range (-17 in. to 383 in. wc).
   - Post accident flooding range (-317 in. to -17 in. & -317 in. to 60 in. wc).

3. HNP-1 and HNP-2 have Category 3 drywell sump level and drain sumps level instrumentation, consisting of continuous level indication, rate of rise indication and high and high-high level alarms (each alarm starts one-sump pump). Timers indicate the duration of sump pump operation for estimating the amount of leakage. No safety-related system is actuated either automatically or manually as a result of the sump level. The drywell sump systems are automatically isolated at the primary containment penetration should an accident signal occur.

4. HNP-1 and HNP-2 monitor radiation level in circulating primary coolant to indicate fuel-cladding failure provided by the following:

   - Condenser off-gas radiation monitor.
   - Main steamline radiation monitors.
   - Primary containment radiation monitors.
   - Post accident-sampling system.
   - Containment hydrogen monitors.

5. RG 1.97, Revision 2, recommends Category 2 instrumentation for reactor building and secondary containment area radiation monitors with a range of 10^{-1} to 10^{4} R/h for Mark I containments. HNP-1 and HNP-2 instruments have a range of 10^{-2} to 10^{+2} mR/h (10^{-5} to 10^{-1} R/h), and 1 to 10^{4} mR/h (10^{-3} to 10 R/h). These instruments are Category 3 instead of Category 2. The use of local radiation exposure rate monitors to detect breach or leakage through primary containment penetration results in ambiguous indications. This is due to the radioactivity in the primary containment, the radioactivity in the fluids flowing in ECCS piping and the amount and location of fluid and electrical penetrations. The use of the plant noble gas effluent monitors is the appropriate way to accomplish the purpose of this variable.

6. RG 1.97 specifies Category 2 instrumentation for suppression chamber spray flow and drywell spray flow variables with a range from 0 to 110% of design flow. HNP-1 and HNP-2 does not provide dedicated flow measurement channels. Instead, the RHR flow elements common to these two sprays and the containment spray is used. The flow is controlled by the position of a throttling valve. Valve lineup, observable in the control room for the suppression chamber spray, drywell spray, and the containment spray, shows which sprays have the indicated flow. Pressure and temperature changes in the drywell and suppression chamber determine the effectiveness of the spray.

TABLE 7.5-1 (SHEET 30 OF 34)

NOTES: (continued)

7. These variables are not indicated/recorded in the MCR.

8. The setpoint used was designated by the nuclear steam supply system (NSSS) supplier to assure positive indication of SRV position. The indication is not influenced by pressure in the drywell. The SRV tailpipe pressure equalizes with drywell pressure through vacuum breakers. For the specific value of the set point calculated and used, reference the HNP-1 and HNP-2 setpoint indexes.

9. HNP-1 and HNP-2 elected to not implement the RG 1.97, Rev. 2 recommendation for SLCS flow. The justification is:

   - The SLCS pump discharge header pressure indicator provides indication the SLCS pump is operating.
   - The level indication in the sodium pentaborate solution storage tank gives indication that flow is occurring.
   - The reactivity change in the reactor as measured by neutron flux is an indication of flow.
   - The motor indicating lights and pump discharge pressure show system operation.
   - The squib valve continuity indicating lights are an indication of flow.

10. The symptomatic Emergency Procedure Guidelines (EPG), Revision 1, as presently approved, do not consider anticipated transient without scram (ATWS) conditions; however, the EPG committee of the BWROG has been developing a draft reactivity control guideline in which procedures are described for raising the reactor water level based on the amount of boron injected into the vessel, as indicated by the SLCS tank level. Additionally, the operator is required to trip the SLCS pumps before a low SLCS tank level is reached, thereby preventing damage to the pumps that would render them useless for future injections during the scenario. Regarding the instrumentation category requirement for variable D18, RG 1.97 indicates that it is a key variable in monitoring SLCS operation. RG 1.97 also states that, in general, key type D variables be designed and qualified to Category 2 requirements. In applying these requirements of RG 1.97 to this instrumentation, the following are noted:

   - The current design basis for the SLCS assumes a need for an alternative method of reactivity control without a concurrent LOCA or high-energy line break. The environment in which the SLCS instrumentation must work is therefore a mild environment for qualification purposes.
   - The current design for the SLCS recognizes that the system has an importance to safety that is less than the importance to safety of the reactor protection system and the ESF. Therefore, in accordance with the graded approach to quality assurance specified in RG 1.97, it is unnecessary to apply a full quality assurance program to this instrumentation. Based on a graded approach to safety, this variable is more appropriately considered a Category 3 variable.
   - SLCS storage tank level instrumentation should meet Category 3 design and qualification criteria. It is realized that the resolution of the ATWS issue may include substantial changes to the SLCS design criteria. At that time, the SLCS instrumentation should be reevaluated to ensure adequacy.

11. Remote cooling water temperature indication is not provided to monitor cooling water temperature to ESF system components. Each area with essential coolers is provided with local area (air) temperature indication, which is available in the MCR. These temperature indications, in conjunction with plant service water flow and cooler status indication, provide the operator with adequate indication as to the status of the cooling capabilities to the ESF system components. HNP-1 and HNP-2 plant service water systems are once-through systems. The cooling water source is the Altamaha River. Thus, the temperature of the cooling water is essentially the river water temperature.

TABLE 7.5-1 (SHEET 31 OF 34)

NOTES: (continued)

12. HNP-1 and HNP-2 instrumentation for cooling water flow to ESF components does not provide direct indication of cooling water flow to ESF system components. HNP-1 and HNP-2 relies instead on the plant service water system pump output pressure and system pressure instrumentation, pump running indication, valve position indication, and equipment room temperatures to indicate system operation. System leaks are detected by the equipment and floor drainage system and room temperature indication. HNP-1 and HNP-2 emergency operating procedures are written around this diverse instrumentation. The instrumentation will show loss of flow due to blockage or piping failure.

13. RG 1.97, Rev. 2, states that radiation exposure rate (inside buildings or areas where access is required to service equipment important to safety) be monitored over the range of 10^{-1} to 10^{4} R/h for detection of significant releases, for release assessment, and for long-term surveillance. In general, access is not required to any area of the secondary containment to service equipment important to safety in a post-accident situation. If and when accessibility is reestablished in the long term, it will be done by a combination of portable radiation survey instruments and post-accident sampling of the secondary containment atmosphere. The existing lower-range (typically 3 decades lower than the RG states) area radiation monitors would be used only in those instances in which radiation levels were very mild. It is BWROG's position that unless plant-specific design requires access to a harsh environment area to service safety-related equipment during an accident, this parameter should be modified to allow credit for existing area radiation monitors. HNP-1 and HNP-2 position is that this parameter is classified as Category 3 with a lower range selected on a plant-specific basis.

14. Main vent stack wide-range radiation monitor system microprocessor panel 1D11-P007 integrates the signals from monitoring panel 1D11-P006. Monitoring panel 1D11-P006 contains two radiation detectors (1D11-RE N055 & N056) whose individual signals are integrated into a composite wide-range signal and recorded on 1D11-RR R631 in the MCR.

    HNP-1 and HNP-2 have normal and wide-range instrumentation with dedicated indicators to monitor noble gas and vent flow rate through common plant vent. The safety parameter display system integrates two sets of instrumentation for a composite range of 10^{-7} to 10^{+5} μCi/cc. The wide-range instruments are Category 2. The normal-range instruments, which provide information for levels of $< 5 \times 10^{-3}$ μCi/cc, are Category 3. The instruments are located in a mild environment.

    HNP-1 and HNP-2 reactor building vent stack wide-range radiation monitor systems microprocessor panels 1, 2D11-P601 integrates the signals from monitoring panels 1, 2D11-P005. Monitoring panels 1, 2D11-P005 contain two noble gas radiation detectors (1, 2D11-RE N048 & N049) whose individual signals are integrated into a composite wide-range signal and recorded on recorders 1, 2D11-RR R631 in the MCR.

15. The BWROG's position states, "For all accidents in which radioactive material would be in the primary containment sump of a BWR Mark I or Mark II containment, this sump will be isolated and will overflow to the suppression pool." Although HNP-1 and HNP-2 do not have direct suppression chamber sample capability, provisions do exist to sample the RHR system, which takes suction from the suppression chamber. In the event of a major core degradation, a sample of the RCS through the post-accident sampling system will provide a conservative estimate of the suppression chamber, since the suppression chamber is the source of makeup for the reactor through a closed loop. For all accidents in which radioactive material would be in the primary containment sump, this sump will be isolated and will overflow to the suppression pool. A suppression pool sample can, therefore, be used as a valid alternative to a containment sump sample.

TABLE 7.5-1 (SHEET 32 OF 34)

NOTES: (continued)

The analysis of ECCS pump-room sumps and other similar auxiliary building sumps is a consideration only if the water is pumped out of the reactor building (e.g., pumped to radwaste). For designs such as HNP-1 and HNP-2 in which sump pumpout is not allowed on a receipt of an accident signal, or in which the water is pumped to the suppression pool, analysis is not necessary. Provisions for sump sampling and analysis should be in accordance with the response to NUREG 0737.

16. a. 1B21-TR R614 inputs from 1B21-TE N004A through H, J through L.

    b. 2B21-TR R614 inputs from 1B21-TE N004A through H, K through M.

17. Control rod position includes 137 control rods with 53 position switches on each rod at the rod position information system cabinet and on the MCR rod digital displays. NOT FULL IN indication includes 47 positions at equal 3-in. intervals providing an indication signal at each locking position and at the halfway point between each locking position.

18. Four SRM neutron flux channels are recorded on the same recorder powered from 120 V-ac. SRM units are powered from 48 V-dc supply. Loops are nonessential but channels A & C are routed via Division I raceway and channels B & D are routed via Division II raceway.

19. Four APRM neutron flux channels are recorded on four recorders and are powered from 120 V-ac. IRM units are powered from 48 V-dc supply. Loops are nonessential but channels A, C, & E are routed via Division I raceway and channels B, D, & F via Division II raceway.

20. Four APRM neutron flux channels are recorded on four recorders and are powered from 120 V-ac. IRM units are powered from 48 V-dc supply. Loops are nonessential but channels A, C, & E are routed via Division I raceway and channels B, D, & F via Division II raceway.

21. Four APRM neutron flux channels are recorded on four recorders and are powered from 120 V-ac. IRM units are powered from 48 V-dc supply. Loops are nonessential but channels A, C, & E are routed via Division I raceway and channels B, D, & F via Division II raceway.

22. Four APRM neutron flux channels are recorded on four recorders and are powered from 120 V-ac. IRM units are powered from 48 V-dc supply. Loops are nonessential but channels A, C, & E are routed via Division I raceway and channels B, D, & F via Division II raceway.

23. Indication located in the reactor building. No indication provided in the MCR.

24. Indication located in the radwaste control room. No indication provided in the MCR.

25. Input from 1, 2T47-TE N001A, B, L, N002, N004, N006, N008, and N009.

TABLE 7.5-1 (SHEET 33 OF 34)

NOTES: (continued)

26. Input from 1, 2T47-TE N001J, K, M, N003, N005, N007, and N010.

27. a. 1T48-TR R647 inputs from 1T48-TE N301A through N311A.

    b. 2T48-TR R647 inputs from 2T48-TE N301A through N303A, N304B, N305A through N311A.

28. Not required per NUREG-0737, Supplement 1.

29. Does not exist at HNP-1 and HNP-2.

30. Suppression pool level as specified for type D variable in Table 1 of RG 1.97, Rev 2, applies only to BWR 6 Mark III containments, and therefore is not applicable to BWR 4 Mark I containments. Suppression pool level has been provided at HNP-1 and HNP-2 as type C variable.

31. Safety parameter display system (SPDS) signal only.

32. RG 1.97, Rev. 2 recommends instrumentation with a range of -9 to +18°F to monitor estimation of atmospheric stability or an analogous range for alternative stability analysis. HNP has instrumentation with a range of -10 to +10°F. Justification for this is that the range is based on RG 1.23, Revision 1, Table 1, Classification of Atmospheric Stability by Temperature Change with Height. HNP range for this variable is included in this table. Estimation of atmospheric stability is common to HNP-1 and HNP-2.

33. BWR core thermocouples are not required per supplement 1 to NUREG-0737.

34. PCIVs that close after receiving an automatic isolation signal for the purpose of containment isolation meet RG 1.97, Rev. 2, requirements for Type B variables.

    - ***HNP-1 Technical Requirements Manual (TRM) Table T7.0-1 (incorporated by reference into the FSAR)*** identifies the isolation signals as Groups 1 through 6, 8 through 11, and isolation signals c, e, f, g, h, i, and j.

    - ***HNP-2 TRM Table T7.0-1 (incorporated by reference into the FSAR)*** identifies the isolation signals as Groups 1 through 12, and isolation signals c, e, f, g, h, i, and j.

35. HNP-1 was licensed without a MSIV LCS and as such the variable is not required on HNP-1.

36. RG 1.97, Rev. 2, recommends drywell atmosphere temperature instrumentation have a range of 40° to 440°F. HNP-2 drywell atmosphere temperature instrumentation has a range of 0 to 400°F. The maximum drywell average temperature during a design basis event would be < 340°F. The maximum temperature for continued operation is 150°F, which provides a significant margin between the temperatures expected in the drywell and the measurement capabilities of the monitoring instrument.

TABLE 7.5-1 (SHEET 34 OF 34)

NOTES: (continued)

37. Units 1 and 2 Technical Specifications Amendments 244 and 188, respectively, allow downgrading the hydrogen and oxygen monitors. The hydrogen monitors may be downgraded from Category 1 to Category 3, and the oxygen monitors from Category 1 to Category 2.

    The instruments in Technical Specifications LCO Table 3.3.3.1-1, “Post Accident Monitoring Instrumentation,” are typically the RG 1.97 Category 1 instruments. Along with the above described allowance for the RG 1.97 downgrade, Amendments 244 and 188 also removed the H_2 and O_2 monitors from the Technical Specifications because they did not meet 10 CFR 50.36 criteria for systems requiring Technical Specification LCOs. It is, however, impractical to downgrade the monitors and provide the electrical separation required by RG 1.75. Consequently, for the time being, Plant Hatch chooses to continue treating these monitors as RG 1.97 Category 1 instruments.

7.6 OTHER SYSTEMS REQUIRED FOR SAFETY AND POWER GENERATION

Although section 7.6 is titled "Other Systems Required For Safety and Power Generation," it is not implied that the systems identified herein do not satisfy safety requirements. The basis of the boiling water reactor (BWR) plant design is such that many systems which have a safety function will also have a power generation function during normal plant operation. In this section, the intention is to describe the safety functions only of these dual role systems. It is also noted that some systems which do not have a direct safety function; e.g., reactor pressure vessel (RPV) instrumentation and process computer, are placed in this section because they are not control systems and would be incorrectly placed in section 7.7. Subsection 7.6.7 identifies the equipment described therein as nonsafety-related to clarify the position.

7.6.1 REFUELING INTERLOCKS

7.6.1.1 Design Bases

Refueling interlocks meet the following safety design bases:

A. During fuel movements in or over the reactor core, all control rods are in their fully inserted positions.

B. No more than one control rod can be withdrawn from its fully inserted position at any time when the reactor is in the refuel mode.

7.6.1.2 System Description

7.6.1.2.1 Identification and Classification

The purpose of the refueling interlocks is to restrict the movement of control rods and the operation of refueling equipment and to reinforce operational procedures that prevent taking the reactor critical during refueling operations. Additional information is provided in paragraph 7.1.2.9.

7.6.1.2.2 Initiating Circuits

The refueling interlocks circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated to prevent the movement of the refueling equipment or withdrawal of control rods (rod block). Circuitry is provided to sense the following conditions:

- All rods inserted.
- Refueling platform positioned near or over the core.
- Refueling platform frame-mounted hoist and auxiliary monorail hoist (fuel loaded).
- Fuel grapple not at full-up position.

7.6.1.2.3 Logic

The indicated conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operation and control rod movement as described on drawing nos. H-24717 through H-24720, H-24781, H-24782, H-24784, and H-24787, and in the following:

A. Refueling platform travel toward the core is stopped when the following three conditions exist concurrently:

   1. Any refueling platform hoist is fuel loaded or the fuel grapple is not in its full-up position.

   2. Not all rods are in.

   3. Refueling platform position is such that the position switch is open (platform near or over the core).

B. With the mode switch in STARTUP, refueling platform travel toward the core is prevented when the refueling platform position switch is open (platform near or over the core).

C. With the mode switch in REFUEL, refueling platform travel toward the core is prevented when the following two conditions exist concurrently:

   1. More than one rod is withdrawn.

   2. The refueling platform position switch is open (platform near or over the core).

D. The refueling platform frame-mounted hoist lift electrical circuit is open when the following three conditions exist concurrently:

   1. Frame-mounted hoist is fuel loaded.

   2. Not all rods are in.

   3. Refueling platform is near or over the core.

E. The refueling platform trolley-mounted hoist lift electrical circuit is open when the following three conditions exist concurrently:

    1. Trolley-mounted hoist is fuel loaded.

    2. Not all rods are in.

    3. Refueling platform is near or over the core.

F. Operation of the telescoping fuel grapple is prevented when the following two conditions exist concurrently:

    1. Not all rods are in.

    2. Refueling platform is near or over the core.

G. With the mode switch in refuel, either of the following conditions prevents a control rod withdrawal:

    1. Refueling platform over the core with a load on any refueling platform hoist or the fuel grapple is not fully up.

    2. Selection of a second rod for movement with any other rod withdrawn from the fully inserted position has occurred.

H. With the mode switch in startup, the following condition prevents a control rod withdrawal:

    1. Refueling platform over the core has occurred.

A two-channel dc circuit indicates that all rods are in. The rod-in condition for each rod is established by the closure of a magnetically operated reed switch in the rod position indicator probe. The rod-in switch must be closed for each rod before the all-rods-in signal is generated; two channels carry the signal. Both channels must register the all-rods-in signal in order for the refueling interlock circuitry to indicate the all-rods-in condition.

During refueling operations, no more than one control rod is permitted to be withdrawn. This restriction is enforced by a redundant logic circuit that uses the all-rods-in signal and a rod selection signal to prevent the selection of a second rod for movement with any other rod not fully inserted. The simultaneous selection of two control rods is prevented by the interconnection arrangement of the select pushbuttons. With the mode switch in the refuel position, the circuitry prevents the withdrawal of more than one control rod and the movement of the refueling platform over the core with any control rod withdrawn. Operation of refueling equipment is prevented by interrupting the power supply to the equipment. The refueling platform is provided with two mechanical switches attached to the platform, which are tripped open by a long, stationary ramp mounted adjacent to the platform rail. The switches open before the platform or any of its hoists are physically located over the reactor vessel to indicate the approach of the platform toward its position over the core.

Load cell readout is accomplished by use of a solid-state load cell for the main hoist. The load cell acts as a sensor that sends a signal, which corresponds to the load on the hoist, to the indicator controller. The indicator controller receives the signal and compares it to three setpoints. The setpoints correspond to hoist loaded, hoist jammed, and slack cables. These setpoints control the operator's ability to maneuver the hoist.

The three hoists on the refueling platform are provided with switches which open when the hoists are fuel loaded. The switches open at a load weight which is lighter than that of a single fuel assembly. This circuitry indicates when fuel is loaded on any hoist.

The telescoping fuel grapple hoist has a limit switch. The switch is open whenever the grapple has descended more than ~ 4 in. from its full-up position. This switch is placed in series with the grapple load switch to ensure interlock operation if the total weight of the bottom section of the telescope plus the fuel is less than the preset load.

7.6.1.2.4 Bypasses and Interlocks

Circuitry is provided to interact with a service platform which is no longer available. A bypass plug allows control rod movement logic to operate correctly in absence of the service platform.

7.6.1.2.5 Redundancy and Diversity

The refueling interlocks are designed such that a single interlock failure will not cause an accident. These refueling interlocks are provided for use during planned refueling operations. Criticality is prevented during the insertion of fuel, provided control rods in the vicinity of the vacant fuel space are fully inserted during the fuel insertion. The interlock systems accomplish this through the:

- Preventing operation of the fuel-loaded refueling equipment over the core whenever any control rod is withdrawn.

- Preventing control rod withdrawal whenever fuel-loaded equipment is over the core.

- Preventing withdrawal of more than one control rod when the mode switch is in the refuel position.

The refueling interlocks have been carefully designed utilizing redundancy of sensors and circuitry to provide a high level of reliability and assurance that the stated design bases are met. Each of the individual refueling interlocks discussed above need not meet the single-failure criterion of Institute of Electrical and Electronics Engineers (IEEE) 279-1971, because the four essentially independent levels of protection provide assurance that the design basis is met. For any of the situations listed in table 7.6-1, a single interlock failure will not cause an accident, result in potential physical damage to fuel, or result in radiation exposure to personnel during fuel handling operations.

7.6.1.2.6 Testability

Complete functional testing of all refueling interlocks before refueling outages positively indicates that the interlocks operate in the situations for which they were designed. The interlocks are subjected to valid operational tests by loading each hoist with a dummy fuel assembly or appropriate test weight, positioning the refueling platform, and withdrawing control rods.

7.6.1.2.7 Power Supply

Both channels are powered by the same power source as the control rod drive (CRD) system. A failure of this power source will prevent any rod motion.

7.6.1.2.8 Environmental Considerations

The refueling equipment is subject to conditions during normal operation which are less severe than those discussed in section 3.11.

7.6.1.2.9 Operational Considerations

The refueling interlocks system is required only during refueling operations.

In the refueling mode, the main control room (MCR) operator has an indicator light for "refueling mode control rod selection permissive" whenever all control rods are fully inserted. He can compare this indication with control rod position data from the computer as well as control rod in/out status display. Furthermore, whenever a control rod withdrawal block situation occurs, the operator receives annunciation and computer logging of the rod block. He can compare these outputs with the status of the variable providing the rod block condition.

Both channels of the control rod withdrawal interlocks must agree that permissive conditions exist in order to move control rods; otherwise, a control rod withdrawal block is placed into effect. Failure of one channel may initiate a rod withdrawal block, but it does prevent application of a valid control rod withdrawal block from the remaining operable channel.

In terms of refueling platform interlocks, the platform operator has visual indication, pushbuttons, and rotary control switches provided for local control of the platform and its hoists. The platform operator can immediately determine whether the platform and hoists are responding to his local instructions. In conjunction with the MCR operator, the local operator can verify proper operation of each of the three categories of interlocks listed previously.

7.6.1.3 Analysis

A. Conformance to General Functional Requirements

The refueling interlocks, in combination with core nuclear design and refueling procedures, limit the probability of an inadvertent criticality. The nuclear characteristics of the core ensure that the reactor is subcritical even when the highest worth control rod is fully withdrawn. Also, refueling procedures are written to avoid situations in which inadvertent criticality is possible. The combination of refueling interlocks for control rods and the refueling platform provides redundant methods of preventing inadvertent criticality even after procedural violations. The interlocks on hoists provide yet another method of avoiding inadvertent criticality.

Table 7.6-1 illustrates the effectiveness of the refueling interlocks. This table considers various operational situations involving rod movement, hoist load conditions, refueling platform movement and position, and mode switch manipulation. The initial conditions in situations 4 and 5 appear to contradict the action of refueling interlocks; because the initial conditions indicate that more than one control rod is withdrawn, yet the mode switch is in the refuel position. Such initial conditions are possible if the rods are withdrawn when the mode switch is in the startup position and then turned to the refuel position. The scram indicated in situation 17 of the table is not a result of the refueling interlocks; it is the response of the reactor protection system (RPS) to having three or more main steam lines with an isolation valve < 90% open when the mode switch is shifted to the RUN position. (When the switch is put into the RUN mode, the main steam pressure must be maintained above 825 psig in order to keep the main steam isolation valves (MSIVs) open. During refueling, reactor and steam pressures are atmospheric, and the valves are already closed.) In all cases, correct operation of the refueling interlock prevents either the operation of loaded refueling equipment over the core when any control rod is withdrawn or the withdrawal of any control rod when fuel loaded refueling equipment is operating over the core. In addition, when the mode switch is in the REFUEL position, only one rod can be withdrawn; selection of a second rod initiates a rod block.

B. Conformance to Specific Regulatory Requirements

The refueling interlocks are designed to exert restraint on the movement of control rods during refueling operations, thus significantly reducing the probability of making the reactor critical. In the unlikely event that criticality did occur, adequate protection is provided by the RPS to handle such a transient, and the refueling interlocks would play no part at this stage of the event. The Hatch Nuclear Plant-Unit 2 (HNP-2) refueling interlocks are exactly the same as those which have been licensed on all similar plants prior to HNP-2.

No specific regulatory requirements apply to refueling interlocks. The refueling interlocks are designed to be normally energized (fail-safe) and to be single-failure tolerant of equipment failures.

IEEE standards do not apply because the refueling interlocks are not required for any postulated design basis accident (DBA) or for safe shutdown.

7.6.2 NEUTRON MONITORING SYSTEM (NMS)

The NMS consists of the following seven major subsystems:

- Source range monitor (SRM) system.
- Intermediate range monitor (IRM) system.
- Local power range monitor (LPRM) system.
- Average power range monitor (APRM) system.
- Rod block monitor (RBM) system.
- Traversing incore probe (TIP) system.
- Oscillation power range monitor (OPRM).

The purpose of the NMS is to detect excessive power generation and thermal hydraulic instabilities in the core and to provide signals to the RPS (section 7.2). It also provides information for operation and control of the reactor. Basic system information is given in table 7.6-2.

Certain portions of the IRM and APRM systems provide a safety function, and portions of the RBM have been designed to meet IEEE 279 (1971). All other portions of the NMS have no safety function.

7.6.2.1 Design Basis

7.6.2.1.1 Source Range Monitor System

A. Safety Design Basis

   The SRM has no safety function.

B. Power Generation Design Basis

   The SRM system is designed to:

- Provide a signal-to-noise ratio of at least 2:1 and a count rate of at least three counts per second with all control rods fully inserted prior to initial power operation (neutron sources and detectors together).

- Indicate during the worst possible startup rod withdrawal conditions a measurable increase in output signal from at least one detecting channel before the reactor period is < 20 s.

- Indicate substantial increases in output signals with the maximum permitted number of SRM system channels out of service during normal reactor startup operations.

- Have channels on scale when the IRM system first indicates neutron flux during a reactor startup.

- Provide a measure of the time rate of change of the neutron flux (reactor period) for operational convenience.

- Generate interlock signals to block control rod withdrawal if the count rate exceeds a preset value or falls below a preset limit (if the IRMs are not above the second range) or if certain electronic failures occur.

7.6.2.1.2 Intermediate Range Monitor System

A. Safety Design Basis

The IRM system generates a trip signal that can be used to prevent fuel damage caused by anticipated operational occurrences (AOOs) which occur while operating in the intermediate power range. The independence and redundancy incorporated in the design of the IRM system are consistent with the safety design bases of the RPS. The IRM system is designed in accordance with IEEE 279-1971, 323-1971, 338-1971, and 355-1971; Regulatory Guide 1.22; and General Design Criteria 13 and 20 through 24 of 10 CFR 50, Appendix A.

B. Power Generation Design Bases

The IRM system generates a trip signal to block rod withdrawal if the IRM system reading exceeds a preset value or if the IRM system is not operating properly. The IRM system has overlapping neutron flux indication relative to the SRM system and power range monitor system.

7.6.2.1.3 Local Power Range Monitor System

A. The LPRM system is designed to:

- Provide signals to the APRM system proportional to the local neutron flux at various locations within the reactor core.
- Provide signals to the RBM system to indicate changes in local relative neutron flux during the movement of control rods.
- Signal high or low local neutron count rate.
- Provide signals proportional to the local neutron flux to drive indication on operator display assemblies and auxiliary devices to be used for operator evaluation of power distribution, local heat flux, minimum critical power ratio (MCPR), and fuel burnup rate.
- Provide a sufficient number of LPRM signals to support the APRM safety design bases.

7.6.2.1.4 Average Power Range Monitor System

A. Safety Design Basis

During the worst permitted input LPRM system bypass conditions, the APRM system generates a trip signal in response to average neutron flux increases resulting from AOOs or thermal-hydraulic instabilities in time to prevent fuel damage. The APRM system is designed in accordance with requirements listed in paragraph 7.6.2.3.4.B. The design is consistent with the requirements of the safety design bases of the RPS. The APRM is not required to meet the environmental qualification requirements of rulemaking 10 CFR 50.49.

B. Power Generation Design Bases

The APRM system provides:

- A continuous indication of average reactor power from 0.0 to 125% of rated thermal power to the MCR and to the process computer.
- Interlock signals for blocking further rod withdrawal to avoid an unnecessary scram actuation.
- A reference power level for the RBM subsystem.

7.6.2.1.5 Rod Block Monitor System

A. Design Basis

The RBM system is designed to:

- Prevent violation of the fuel integrity safety limit that may result from a single rod withdrawal error.
- Provide a signal used by the operator to evaluate the change in the local relative power level during control rod movement.
- Prevent any single short or open of any single input to the RBM system from affecting any other RBM inputs.
- Meet General Design Criterion 24 (GDC) of 10 CFR 50, Appendix A.

7.6.2.1.6 Traversing Incore Probe Subsystem

A. Safety Design Basis

The TIP subsystem has no safety design basis.

B. Power Generation Design Basis

The TIP subsystem is designed to:

- Provide a signal proportional to the axial gamma flux distribution at selected small axial intervals over the regions of the core where LPRM system detector assemblies are located. This signal is of high precision to allow reliable calibration of LPRM system gains.
- Provide accurate indication of the position of the flux measurement which allows pointwise or continuous measurement of the axial gamma flux distribution

7.6.2.1.7 Oscillation Power Range Monitor

A. Safety Design Basis

1. The design of the OPRM subsystem is capable of generating a scram trip signal in response to neutron flux oscillations resulting from thermal-hydraulic instability in time to prevent fuel damage.

2. The design of the OPRM subsystem is consistent with the requirements of the safety design basis of the RPS.

B. Power Generation Design Basis

The OPRM subsystem provides the operator with front panel readouts showing the status of the OPRM subsystem and an oscillation pre-trip alarm when one of the instability algorithms (period based, amplitude based, or growth based) for an operable OPRM cell has exceeded user defined setpoints. The OPRM also provides an oscillation trip enable alarm that indicates when the reactor has reached the operating region where instability can occur and the oscillation trip output has been enabled (no longer bypassed). Together these readouts and alarms provide warnings to help assure that the operator will know when the plant is operating in a region or at a condition that may lead to an OPRM trip, and allow the operator to take appropriate action.

7.6.2.2 System Description

7.6.2.2.1 Source Range Monitor System

A. Circuit Description

The SRM provides neutron flux information during reactor startup and low flux level operations. There are four SRM channels. Each SRM channel includes one detector that can be physically positioned in the core from the MCR (figure 7.6-1 and drawing no. S-25562).

The core locations of the SRM detectors are shown on figure 7.6-2. The detectors are inserted into the core for a reactor startup. They can be withdrawn without penalty of rod withdrawal block if the indicated count rate is above the preset limit or if the IRM is on the third range or above (figure 7.6-3).

The power for the monitors is supplied from the two separate +24-V-dc buses. Two monitors are powered from each bus. The detector drives are powered by a 120-208-V-ac, three-phase bus.

Each detector assembly consists of a miniature fission chamber and a low loss quartz-fiber-insulated transmission cable. The sensitivity of the detector is 1.2 x 10-3 Hz/nv nominal, 5.0 x 10-4 Hz/nv minimum, and 2.5 x 10-3 Hz/nv maximum. The detector cable is connected underneath the reactor vessel to a shielded coaxial cable. This shielded cable carries the pulses to a pulse current preamplifier located outside the primary containment.

The detector and cable are located inside the reactor vessel in a dry tube sealed against RPV pressure. A remote-controlled detector drive system moves the detector along the dry tube.

Vertical positioning of the chamber is possible from 17 in. above the centerline of the active length of fuel to 2 1/2 ft below the reactor fuel region as shown on drawing no. S-25562. When a detector arrives at a travel endpoint, detector motion is automatically stopped. SRM/IRM drive control logic is presented on drawing no. H-24727. The electronics for the SRMs and their trips and bypasses are located in one cabinet. Source range signal conditioning equipment is designed so that it can be used for open-core experiments.

A charge sensitive preamplifier provides amplification and impedance matching for the signal conditioning electronics (figure 7.6-4). The signal conditioning equipment converts the current pulses to analog dc voltages that correspond to the logarithm of the count rate. The equipment also derives the period. The output is displayed on front panel meters and is provided to remote meters and recorders.

The logarithm of the count rate meter displays the rate of occurrence of the input current pulses. The period meter displays the time in sections for the count rate to change by a factor of 2.72. In addition, the equipment contains integral test and calibration circuits, trip circuits, power supplies, and selector circuits.

The trip outputs of the SRM operate in the fail-safe mode. Loss of power to the SRM causes the associated outputs to become tripped (drawing no. H-24725).

The SRM provides signals indicating SRM upscale, downscale, inoperative, and incorrect detector position to the reactor manual control system (RMCS) to block rod withdrawal under certain conditions. Any SRM channel can initiate a rod block.

These rod-blocking functions are discussed in subsection 7.7.1. Appropriate lights and annunciators are also actuated to indicate the existence of these conditions (table 7.6-3). One in one group of four SRM channels can be bypassed at any one time by the operation of a switch on the operator console.

B. Testability

Each SRM channel is tested and calibrated. Inspection and testing are performed on the SRM detector drive mechanism as required. The mechanism can be checked for full insertion and retraction capability. The various combinations of SRM trips can be introduced to ensure the operability of the rod blocking functions.

C. Environmental Considerations

The wiring, cables, and connectors located within the drywell are designed to meet the environmental conditions stated in section 3.11.

7.6.2.2.2 Intermediate Range Monitor System

A. Identification

The IRM monitors neutron flux from the upper portion of the SRM range to the lower portion of the power range monitoring subsystems. The IRM system has eight IRM channels, each of which includes one detector that can be positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to the RUN position and the APRMs are operative.

B. Power Supply

Power is supplied separately from the two ± 24-V-dc buses. The supplies are split according to their use so that loss of a power supply results in the loss of only one trip system of the RPS.

C. Physical Arrangement

Each detector assembly consists of a miniature fission chamber attached to a low-loss quartz-fiber-insulated transmission cable. When coupled to the signal conditioning equipment, the detector produces a reading of ~ 30% on the most sensitive range with a neutron flux of 108 nv. The detector cable is connected underneath the reactor vessel to a shielded cable that carries the pulses generated in the fission chamber through the primary containment to the preamplifier.

The detector and cable are located in the drywell. They are movable in the same manner as the SRM detectors and use the same type of mechanical arrangement (drawing no. S-25562) and power supply.

D. Signal Conditioning

A voltage amplifier unit located outside the primary containment serves as a preamplifier. This unit converts the current pulses to voltage pulses, modifies the voltage signal, and provides impedance matching. The preamplifier output signal is coupled by a cable to the IRM signal conditioning electronics as shown on figure 7.6-5.

Each IRM channel receives its input signal from the preamplifier and operates on it with various combinations of preamplification gain and amplifier attenuation ratios. The amplification and attenuation ratios of the IRM and preamplifier are selected by an operator console-mounted range switch that provides 10 ranges of increasing attenuation acting on the signal from the fission chamber (the first 6 ranges are called low range and the last 4 ranges are called high range). As the neutron flux of the reactor core increases from 1 x 108 nv to 1.5 x 1013 nv, the signal from the fission chamber is attenuated to keep the input signal to the inverter in the same range. The output signal, which is proportional to neutron flux

at the detector, is amplified and supplied to a locally mounted meter. Outputs are also provided for a remote meter and recorder.

E. Trip Functions

The IRM is divided into two groups of IRM channels arranged in the core as shown on figure 7.6-2. Each group is associated with one of the two trip systems of the RPS. Two IRM channels and their trip auxiliaries are installed in each bay of a four-bay cabinet. Full-length side covers isolate the cabinet bays. The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising intermediate range neutron monitoring.

Each IRM channel includes four trip circuits as standard equipment. One trip circuit is used as an instrument trouble trip. It operates only when the high voltage drops below a preset level, when one of the modules is not plugged in, or when the operate-calibrate switch is not in the operate position. Each of the other trip circuits can be specified to trip when preset downscale or upscale levels are reached.

The trip functions actuated by the IRM trips are indicated on table 7.6-4. Even though the trip setpoint (120) is within 5% of the high end of the calibrated range (0-125), it must be realized that these instruments have an indicating function for the particular process parameter; and the choice of scale range is influenced by the desired readability during normal operation.

Many years of experience have been gained with these instruments in use under identical conditions of application to those of HNP-2. Based on a substantial amount of data from operating plants, an analysis has been made of trip setpoint drift and variation. This work has clearly indicated that there is no correlation between setpoint drift and scale position for the types of instrument identified.

The reactor mode switch determines whether IRM trips are effective in initiating a rod block or a reactor scram (drawing no. H24724). Subsection 7.7.1 describes the IRM rod block trips. With the reactor mode switch in the REFUEL or STARTUP position, an IRM upscale or inoperative trip signal actuates a NMS trip of the RPS. Only one of the IRM channels must trip to initiate a NMS trip of the associated trip system of the RPS.

F. Testability

Each IRM channel is tested and calibrated using the procedures listed in the IRM instruction manual. The IRM detector drive mechanisms and the IRM rod blocking functions are checked in the same manner as for the SRM channels. Each IRM channel can be checked to ensure that the IRM high flux scram function is operable.

G. Environmental Considerations

The wiring, cables, and connectors located in the primary containment are designed for the same environmental conditions as the SRMs. (See section 3.11.)

7.6.2.2.3 Local Power Range Monitor System

A. Equipment Design

B. Identification

The LPRM system consists of fission chamber detectors, signal-conditioning equipment, and trip functions. The LPRM system also provides outputs to the APRM, OPRM, RBM, and process computer.

C. Power Supply

The high-voltage power supply (HVPS) modules provide variable 0 to 200-V-dc to power the LPRM detectors. The HVPS current rating is 120 mA. The 386SX computer module controls the HVPS output voltage and current via the data bus and a digital-to-analog (D/A) converter on the broadcaster module.

Two independently controlled HVPS modules are used per APRM chassis. One module provides the normal supply of high voltage and powers all LPRM detectors connected to the APRM chassis. The second module serves as a backup power supply and provides power to a bypassed LPRM detector selected for current/voltage curve plotting. If the self-test detects failure of the normal power supply, the backup power supply automatically switches to supply high voltage to the LPRM detectors and a self-test alarm is issued. In this event, the APRM is incapable of performing current/voltage plotting until two fully functional HVPS modules are available.

D. Physical Arrangement

The LPRMs include 31 LPRM detector strings having detectors located at different axial heights in the core. Each string contains four fission chambers. These assemblies are distributed to monitor four horizontal planes throughout the core. Figure 7.6-6 shows the LPRM detector radial layout scheme that provides a detector assembly at every fourth intersection of the water channels around the fuel bundles. Every location has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant.

The detector assemblies (drawing no. S-25124) are inserted in the core in spaces between the fuel assemblies (figure 7.6-6). They are inserted through thimbles mounted permanently at the bottom of the core lattice and penetrate the bottom of the reactor vessel. These thimbles are welded to the reactor vessel at the

penetration point. They extend down into the access area below the reactor vessel where they terminate in a flange. The flange mates to the mounting flange on the incore detector assembly. The detector assemblies are locked at the top end to the top fuel guide by means of a spring-loaded plunger. Special water sealing caps are placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents loss of reactor coolant water on removal of an assembly and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

Each LPRM detector assembly contains four miniature fission chambers with an associated solid sheath cable. The chambers are vertically spaced in the LPRM detector assemblies in a way that gives adequate axial coverage of the core, thus complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each fission chamber produces a current that is coupled with the LPRM signal conditioning equipment to provide the desired scale indications.

Each miniature chamber consists of two concentric cylinders which act as electrodes. The inner cylinder (the collector) is mounted on insulators and is separated from the outer cylinder by a small gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the Uranium-coated outer electrode. The chamber is operated at a polarizing potential of ~ 100 V-dc. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage and has a linearity of ± 1% over the design operating range.(1)

The seals in the LPRM gradually undergo fast neutron damage, and leakage may occur between the chamber and its associated cable. Once the seal has started leaking, the nonlinearity of the LPRM increases to a nominal ± 2% of full scale. The leaking seal LPRM should be recalibrated as soon as possible. Each assembly also contains a calibration tube for a TIP. The enclosing tube around the entire assembly contains holes that allow circulation of the reactor coolant water to cool the fission chambers. Numerous tests have been performed on the chamber assemblies including tests of linearity, gamma sensitivity, and cable effects.(1) These tests and experience in operating reactors provide confidence in the ability of the LPRM system to monitor neutron flux to the design accuracy throughout design lifetime.

E. Signal Conditioning

The current signals from the LPRM detectors are transmitted to the LPRM input module in the APRM chassis located in the MCR. The current signal from a chamber is transmitted directly to its amplifier through shielded cable. The amplifier is a linear current amplifier whose voltage output is proportional to the

current input and to the magnitude of the neutron flux. The amplifier output is "read" by digital processing electronics. The digital electronics applies hardware gain corrections, performs filtering, and applies the LPRM gain factors. The digital electronics provides suitable output signals for the computer, recorders and annunciators. The LPRM amplifiers also isolate the detector signals from the rest of the processing so that individual fault in one LPRM signals path will not affect other LPRM signals.

The LPRM signals are indicated on the reactor console. When a central control rod is selected for movement, the LPRM values associated with the nearest 16 LPRM detectors are displayed on operator display assemblies. Each of the four axially spaced LPRM detector signals from each of the four LPRM assemblies is displayed. The operator can readily obtain readings of all the LPRM amplifiers by selecting the control rods in the correct order or by selecting summary LPRM screens on the operator display assembly.

F. Trip Functions

The trip function for the LPRM provides trip signals to activate displays, instrument inoperative signals, and annunciators. Table 7.6-5 indicates the trips.
The trip levels can be adjusted to an accuracy of ± 0.1% and a hysteresis of ± 1% flux. The outputs for the trip functions are designed to go to the "tripped" state on loss of power to the processing electronics.

G. Testability

LPRM channels are calibrated using data from previous full power runs and TIP data which are tested.

H. Environmental Considerations

Each individual chamber of the assembly is a moisture-proof, pressure-sealed unit. The chambers are designed to operate during the conditions described in section 3.11.

7.6.2.2.4 Average Power Range Monitor System

A. Equipment Design

B. Identification

The APRM system has four APRM channels. Each channel uses input signals from a number of LPRM channels. Each of the four APRM channels provides inputs to four two-out-of-four voter channels. Two of the voter channels are associated with each of the RPS trip systems. All four APRM channels are associated with both of the RPS trip systems in that they provide inputs to each of the four voter channels (figure 7.6-7, sheet 2 of 5).

C. Power Supply

Each APRM chassis receives power from one low-voltage power supply (LVPS) module connected to 120-V-ac RPS bus A and one LVPS module connected to 120-V-ac RPS bus B (figure 7.6-7, sheet 1 of 5). Each APRM's two-out-of-four voter logic module receives power from the RPS bus associated with the APRM channel's trip outputs, as well as from the APRM chassis. Electrical isolation between power sources and associated circuits is provided.

D. Signal Conditioning

The APRMs use digital electronic equipment that averages the output signals from a selected set of LPRMs, generates trip outputs via the two-out-of-four voter channels (7.6.2.2.4.E), and provides signals to readout equipment. Each APRM channel can average the output signals from up to 31 LPRM channels. Assignment of LPRM channels to an APRM is shown on drawing no. H-26993. The letters at the detector locations shown on drawing no. H-26993 refer to the axial positions of the detectors in the LPRM detector assembly. Position A is the bottom position, positions B and C are above position A, and position D is the topmost LPRM detector position. The pattern provides LPRM signals from all four core axial LPRM detector positions throughout the core. Some LPRM detectors may be bypassed, but the averaging logic automatically corrects for these detectors by removing them from the average. The APRM value calculated from the LPRM inputs is adjusted by a digitally entered factor to allow calibration of the APRM to core thermal power based upon heat balance.

Four separate transmitters on each of two recirculation loops, eight total, (figure 7.6-7, sheet 5 of 5) route output signals to four APRM chassis. Each APRM processes and sums transmitter signals (two total, one per loop) from its flow transmitter inputs. Each APRM sends its total flow signal to both RBMs to provide an alarm when the difference between the maximum and minimum values for total recirculation flow exceeds the setpoint. Each APRM uses the flow signal it processes "as is" for APRM and OPRM trip functions. Each RBM uses the flow signal it receives from its "home" APRM or alternate APRM if the "home" APRM is unavailable. Each APRM compares its own processed flow signal to a high

setpoint and issues rod block and alarms if the setpoint is exceeded (table 7.6-7). Bypass of the APRM channel bypasses the flow functions (no separate flow signal bypass).

All APRM channels are powered redundantly, via intermediate low voltage dc power supplies, from both the A and B RPS ac power buses A and B. The LPRM signal processing equipment is powered by the same sources as the associated APRM channels.

E. Trip Function

The digital electronics for the APRMs provides trip signals directly to the RMCS and via the APRM two-out-of-four voter channels to RPS. Any two unbypassed APRM channels, via the APRM two-out-of-four voter channels, can initiate an RPS trip in both RPS trip systems. Any unbypassed APRM can initiate a rod block, depending upon the position of the reactor mode switch. Table 7.6-7 lists the APRM trip functions. Section 7.7.1 describes in more detail the APRM rod block functions.

The APRM simulated thermal power upscale rod block and scram trip setpoints are varied as a function of reactor recirculation flow. The slope of the upscale rod block and scram trip response curves is set to track the required trip setpoint with recirculation flow changes.

At least two unbypassed APRM channels must be in the upscale or inoperative trip state to cause an RPS trip output from the APRM two-out-of-four voter channels. In that condition, all four voter channels will provide an RPS trip output, two to each RPS trip system. If only one unbypassed APRM channel is providing a trip output, each of the four APRM two-out-of-four voter channels will have a half-trip, but no trip signals will be sent to the RPS. The trips from one APRM can be bypassed by operator action in the MCR. Trip outputs to the RPS are transmitted by removing voltage to a relay coil, so that loss of power results in actuating the RPS trips. A simplified APRM/RPS interface circuit arrangement is shown in figure 7.6-7, sheet 3 of 5.

In the startup mode of operation, the APRM “fixed” upscale trip setpoint is set down to a low level to assist the operator in startup procedures. This trip function is provided in addition to the existing IRM upscale trip in the startup mode. The trip settings are listed in table 7.6-7.

The trip functions are performed by digital comparisons in APRM electronics. The APRM flux value is developed by averaging the LPRM signals and adjusting the average, using the gain adjustment factor from heat balance calculations, to be APRM power. To calculate simulated thermal power the APRM power is processed through a first order filter with a 6-s time constant. These calculations are all performed by the digital processor and result in a digital representation of APRM and simulated thermal power. For each RPS trip and rod block alarm the APRM power or simulated thermal power, as applicable (table 7.6-7), is digitally

compared to the setpoint that was previously entered and stored. If the power value exceeds the setpoint, the applicable trip is issued.

F. Testability

APRM channels are calibrated using data from previous full power runs and are tested by procedures in the applicable instruction manual. Each APRM channel can be tested individually for the operability of the APRM scram and rod blocking functions by introducing test signals.

G. Environmental Considerations

All APRM equipment is installed and operated in the MCR environment as discussed in section 3.11.

7.6.2.2.5 Rod Block Monitor System

A. Equipment Design

The RBM system is integral with the NMS which is presently identified in subsection 7.6.2. The RBM design basis is included in paragraph 7.6.2.1.5. The RBM is adequately described in terms of initiating circuits, logic, bypasses, interlocks, redundancy, diversity, and actuated devices as required by section 7.6 of the Standard Format for Final Safety Analysis Reports (FSARs). Changes made to the RBM as part of the Average Power Range Monitor, Rod Block Monitor, and Technical Specifications (ARTS) Improvements Program are described in detail in reference 3. HNP-2 was the first United States plant to install the ARTS RBM. The RBMs are designed to meet the requirements of IEEE 279, with the exception of the following physical limitations:

Limitation	Reason
A single rod select pushbutton is used for selection of a rod.	A single pushbutton for selection of a rod is provided but redundant contacts are provided on the pushbutton.
The rod withdrawal block outputs from the rod block monitor are carried to a single cabinet for connection into the RMCS.	Each RBM activates a distinctive annunciating block (i.e., RBM A activates annunciating rod block A; RBM B activates annunciating rod block B) used in different portions of RMCS circuits. Both RBMs actuate a single non-annunciating rod block used in one portion of RMCS circuit (section 7.7).
A single switch allows one-out-of-two bypasses of RBM outputs to the RMCS.	A single switch is provided; however, isolation requirements are maintained.

Separability and redundancy of input signals.	These features improve similarity of channel responses.

B. Identification

The RBM system has two channels, each using input signals from a number of LPRM channels. A trip signal from either RBM channel initiates a rod block. One RBM channel can be bypassed without loss of subsystem function. The RBM receives LPRM signals and the simulated thermal power value from an assigned "master" APRM and receives the identity of the selected control rod from the rod control system.

C. Power Supply

Each RBM chassis receives power from one LVPS module connected to 120-V-ac RPS bus A and one LVPS module connected to 120-V-ac RPS bus B (figure 7.6-7, sheet 1 of 5).

D. Signal Conditioning

The RBM signal is generated by averaging a set of LPRM signals. The LPRM signal used depends upon the control rod selected. Upon selection of a rod for withdrawal or insertion, the two RBM channels automatically select the conditioned signals from the LPRMs around that rod. (Figure 7.6.8, sheet 1 of 2, shows examples of the four possible LPRM/selected rod assignment combinations.) For a typical nonedge rod, each RBM channel averages LPRM inputs from two of the four B-position and D-position detectors, and all four of the C-position detectors (figure 7.6-8, sheet 2 of 2). A-position LPRM detectors are not included in the RBM averages, but are displayed in the MCR. When a rod near, but not at, the edge of the core is selected, where there are fewer than four but at least two LPRM strings around the rod, the number of detectors used by the RBM channels is either six or four depending upon how many LPRM strings are available. If a detector in the LPRM system was bypassed the detector is automatically deleted from the RBM processing and the averaging logic is adjusted to average only the remaining detectors.

After selection of a control rod, each RBM channel calculates the average of the related LPRM detectors and calculates a gain factor that will adjust the average to 100. Thereafter, until another rod is selected, the gain factor is applied to the LPRM average to obtain the RBM signal value. The RBM signal value is compared to RBM trip setpoints (paragraph 7.6.2.2.5.E).

When a peripheral rod is selected, or if the simulated thermal power value from the RBM’s associated APRM is below the automatic bypass level (~ 30% power), the RBM function is automatically bypassed, the rod block outputs are set to “permissive”, and the RBM average is set to zero.

The RBM chassis is also assigned some APRM support functions to simplify the overall system architecture. The RBM provides the communication path for APRM information to the plant computer and provides the path for downloading LPRM and APRM gain adjustment factors and reference values. The RBM chassis compares the total flow signals developed by each APRM and issues an alarm if the difference exceeds a pre-set value.

E. Trip Function

The RBM supplies a trip signal to the RMCS to inhibit control rod withdrawal. The trip is initiated when RBM signal value exceeds the rod block setpoint. There are three rod block setpoints. These setpoints are a function of the core thermal power limit. The three setpoints are each a percentage above the RBM initial value of 100. The particular setpoint applied is selected based upon the simulated thermal power value from the RBM's associated APRM channel. (An alternate APRM channel is assigned and is automatically used for inputs if the primary APRM channel is bypassed or inoperative.) Higher APRM simulated thermal power values select a lower setpoint. That is, at higher power levels, the percentage increase in the RBM value allowed is less than at lower power levels. The power ranges over which each is implemented are adjustable. The ranges of adjustability are given in NEDC-30474-P[(3)]. The specific values of the setpoints and the power ranges of applicability are given in the plant Technical Specifications.

Either RBM channel can prevent rod movement. The operator can bypass one of the two RBMs at any time. Either RBM can inhibit control rod withdrawal (drawing no. H-24726). Table 7.6-8 indicates the RBM system trips.

F. Isolation Separation and Redundancy

The following features are included in RBM design:

- Redundant, separate, and isolated RBM channels.

- Redundant, separate, isolated rod selection information (including isolated contacts for each rod selection pushbutton) provided directly to each RBM channel.

- Independent, separate, and electrically isolated. APRM reference signals to each RBM channel.

- Independent and isolated RBM level readouts and status displays from the RBM channels.

- Mechanical barrier between channel A and channel B of the manual bypass switch.

- Independent, separate, and isolated rod block signals from the RBM channels to the RMCS circuitry.

G. Testability

The RBM channels are tested and calibrated. The RBMs are functionally tested by introducing test signals into the RBM channels.

H. Environmental Considerations

See description for APRM in 7.6.2.2.4.G.

7.6.2.2.6 Traversing Incore Probe System

A. Equipment Design

B. Circuit Description

The TIP system includes four TIP assemblies. Each TIP machine includes the following components:

- One TIP.
- One drive mechanism.
- One indexing mechanism.
- Up to 10 incore guide tubes.
- One chamber shield.

The subsystem allows calibration of LPRM signals by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core. The guide tubes inside the reactor are divided into groups. Each group has its own associated TIP machine.

C. Physical Arrangement

A TIP drive mechanism uses an ion chamber attached to a flexible drive cable. The cable is driven from outside the drywell by a gearbox assembly. The flexible cable is contained by guide tubes that penetrate the reactor core. The guide tubes are a part of the LPRM detector assembly. The indexing mechanism allows the use of a single detector in any one of 10 different tube paths. The tenth tube is used for TIP cross calibration with the other TIP machines.

The control system provides both manual and semiautomatic operation. Electronics on the TIP panel amplify and display the TIP signal. Core position versus gamma flux can be recorded on an X-Y recorder in the MCR and is provided to the computer. A block diagram of the drive system is shown on figure 7.6-9.

The heart of each TIP machine is the gamma TIP probe. (See figure 7.6-10.) It consists of an ion chamber and the associated signal drive cable. The gamma TIP is designed to operate in a gamma flux field of 2.8×10^9 R/h in the same neutron flux field as the previous neutron-sensitive TIP. The operating voltage is ~ 100 V dc.[1]

The signal current from the detector is transmitted from the TIP to amplifiers and readout equipment by means of a signal cable, which is an integral part of the mechanical drive cable. The cable drive mechanism contains a drive motor and gearbox, (driving the cable in the manner of a rack and pinion), a cable takeup reel, a motor controller, an electrical connector panel, and a probe position encoder transducer. The transducer provides analog signals to a digital encoder in the control unit which, in turn, provides digital pulses to the control unit for positioning the TIP at specific locations along the guide tube.

The drive mechanism inserts and withdraws the TIP and its cable from the reactor and provides detector position indication signals. The variable speed drive motor is preset to provide two speeds, a high speed for insertion and withdrawal (90 ft/min maximum) and a low speed for scanning the reactor core (7.5 ft/min minimum). These speeds can be adjusted within this range as required. The drive motor is equipped with a dynamic braking resistor to prevent overshoot and an overload release clutch that disengages when the torque on the drive cable reaches 250 in.-lb. A takeup reel is included in the cable drive mechanism to coil the drive cable as it is withdrawn from the reactor. This reel makes it possible to connect the TIP and its cable to the amplifier through a connector rather than slip rings. This reduces possible noise and maintenance problems.

The analog position encoder transducer is driven directly from the output shaft of the cable drive motor and the analog signal processed by the encoder electronics in the control unit. The resulting decimal position signal and the flux amplifier output are used to plot gamma flux versus TIP position. The TIP position signal is also available to the process computer. The encoder electronics are used to position the TIP in the guide tube with a linear position accuracy of ± 1 in. The encoder electronics can control TIP positions at the top of the core for initiation of scan and at the bottom of the core for changing to fast withdrawal speed.

A circular transfer machine with 10 indexing points functions as an indexing mechanism. One of these locations is for the guide tube common to all the TIP systems. Indexing to a particular tube location is initiated manually at the control panel by means of an electronic touch pad that energizes the electrically actuated rotating mechanism.

The tube transfer mechanism is part of the indexing mechanism and consists of a fixed circular plate containing 10 holes on the reactor side that mate to a rotating single-hole plate. The rotating plate aligns and mechanically locks with each fixed hole position in succession. The indexing mechanism is actuated by a motor-operated rotating drive. Electrical interlocks prevent the indexing mechanism from operating if any part of the detector/cable assembly is forward of the parked position or if the channel selected is an already occupied common calibration tube. Additional electrical interlocks prevent the cable drive motor from moving the cable until the transfer mechanisms have indexed to the preselected guide tube location (drawing no. H-24785).

A valve system is provided with a valve on each guide tube entering the primary containment. These valves are closed except when the TIP system is in operation. A ball valve and a cable-shearing valve are mounted in the guide tubing just outside the primary containment. They prevent the loss of containment integrity and include the reactor vessel. A valve is also provided for a nitrogen gas purge line to the indexing mechanisms. A guide tube ball valve opens only when the TIP is being inserted. The shear valve is used only if containment isolation is required when the TIP is beyond the ball valve and power to the TIP system fails. The shear valve, which is controlled by a manually operated keylock switch, can cut the cable and close off the guide tube. The shear valves are actuated by detonation squibs. The continuity of the squib circuits is monitored by indicator lights in the MCR.

A guide tube ball valve is normally deenergized and is in the closed position. When the TIP starts forward, the valve is energized and opens. As the valve opens, it actuates a set of contacts which gives a signal light indication at the TIP control panel. The contacts also bypass an inhibit limit switch which automatically stops TIP motion if the ball valve does not open on command (drawing no. H-24785).

D. Signal Conditioning

The readout instruments and electrical controls for the TIP machines are mounted in a cabinet in the MCR. Because there are several groups of guide tubes, each with an associated TIP machine, there are also several groups of readout equipment controls mounted in the cabinet. Each set of readout equipment consists of a dc amplifier and a dc power supply for the TIP polarizing voltage. A common X-Y recorder can be used to record the flux variations of each scan. An X-Y output is provided for use by the process computer. The probe and cable leakages contribute < 1% of indicated reading. For normal operating conditions, the flux amplifier is linear to within ±1.0% of full scale and drifts < ±1.0% of full scale during a 100-h period at design operating conditions. Actual operating experience has shown the system to reproduce within 1.0% of full scale in a sequence of tests.(1)

E. Testability

The TIP system equipment is tested and calibrated using heat balance data and by use of the common channel.

F. Environmental Considerations

The equipment and cabling located in the primary containment are designed for continuous duty in the environment discussed in section 3.11.

7.6.2.2.7 Oscillation Power Range Monitor

A. Equipment Design

The OPRM monitors the core for power oscillations indicative of a core thermal-hydraulic instability. The OPRM uses “cells” of detectors selected from the total available to the APRM channel. The criteria used to select the cells include consideration of all anticipated “phases” of oscillations. The Boiling Water Reactor Owners Group (BWROG) defined the instability OPRM detect-and-suppress trip function utilizing LPRM inputs from the LPRM function. These signals are evaluated using algorithms and logic defined by the BWROG. The OPRM is designed to detect reactor core thermal-hydraulic instability and provide appropriate readouts, trips, and alarms (figure 7.6-7, sheet 2 of 5).

B. Identification

The OPRM subsystem has four OPRM channels each of which uses input signals from a number of LPRM channels. Each of the four OPRM channels provides inputs to four APRM two-out-of-four voter channels. Two of the voter channels are associated with each of the RPS trip systems. All four OPRM channels are associated with both of the RPS trip systems in that they provide inputs to each of the four voter channels.

The OPRM functions are accomplished in the same equipment that performs the APRM functions (figure 7.6-7, sheet 2 of 5). The two-out-of-four voter channels perform a vote of the OPRM channel trip outputs separate from that performed for the APRM trip outputs. As a result, an OPRM trip in one channel and an APRM trip on another will not result in an RPS trip.

C. Power Supply

All OPRM channels operate in the APRM hardware that is powered redundantly, via intermediate low voltage dc power supplies, from the RPS ac power buses A and B. Each OPRM two-out-of-four voter channel receives power from the same 120-V-ac power as the RPS trip system with which it is associated (figure 7.6-7, sheet 1 of 5).

D. Signal Conditioning

The OPRMs use digital electronic equipment that separately averages the output signals from LPRMs in each OPRM "cell" (one to three LPRM detectors per cell). The OPRM equipment processes these cell averages through three algorithms, each monitoring a different dynamic characteristic (period-based, amplitude-based, and growth-based algorithm). The OPRM generates trip outputs via the two-out-of-four voter channels (paragraph 7.6.2.2.4.E) and provides signals to readout equipment when one or more of the instability algorithms has detected an instability condition for an operable OPRM cell. LPRM detectors are assigned to OPRM cells as an equipment setup action and are chosen to assure monitoring of all portions of the core. The algorithms include trip setpoints that are also entered as equipment setup action.

The OPRM logic receives the simulated thermal power signal and recirculation flow from the APRM processing logic. The OPRM trips are enabled only when the plant is operating above a minimum power level as indicated by simulated thermal power signal (26%) and below a maximum recirculation flow value (≤ 60%). In all operating conditions outside this range, the OPRM trip is disabled.

All APRM channels are powered redundantly, via intermediate low voltage dc power supplies, from RPS ac power buses A and B. The LPRM signal processing equipment is powered by the same sources as the associated APRM channels. The trip and alarm status of the OPRM channels is indicated at the local instrument, and is either indicated or annunciated at the plant operator's panel.

E. Trip Function

The digital electronics for the OPRMs provides trip signals via the OPRM two-out-of-four voter channels, to the RPS. Although the OPRM channels and APRM channels share the same two-out-of-four voter channel, the trip outputs of the OPRM function are voted separately from the APRM trip outputs.

At least two unbypassed OPRM channels must be in the trip state to cause an RPS trip output from the OPRM two-out-of-four voter channels. In that condition, all four-voter channels will provide an RPS trip output, two to each RPS trip system. If only one unbypassed OPRM channel is providing a trip output, each of the four two-out-of-four voter channels will have a half-trip, but no trip signals will be sent to the RPS. The trips from one OPRM can be bypassed by operator action in the MCR; however, in this state, both the OPRM and the associated APRM channels are bypassed. Trip outputs to the RPS are transmitted by removing voltage to a relay coil so that loss of power results in actuating the RPS trips. A simplified APRM/OPRM/RPS interface circuit arrangement is shown in figure 7.2-2.

The trip functions are performed by digital comparisons in the OPRM electronics. The LPRM flux values from each of the unbypassed detectors in an OPRM cell are combined, after processing by the LPRM subsystem, by adding the detector values and filtering the sum to a steady-state average. The summation without filtering is

compared to the average using the three different OPRM algorithms; i.e., the period-based, amplitude-based and growth-based algorithms. If after processing the signals from detectors in any of the OPRM cells in an OPRM channel indicate conditions or characteristics exceeding setpoint values, an OPRM trip is issued from that channel.

The OPRM trips are enabled only when the plant is operating above a minimum power level (26%) and below a maximum recirculation flow value (nominally 60%). In all operating conditions outside this range, the OPRM trip is disabled.

The trip and alarm status of the OPRM channels is indicated at the local instrument and indicated or annunciated at the plant operator's panel.

F. Testability

OPRM channels require no direct calibration. APRM calibrations assure the OPRM channels receive calibrated LPRM, simulated thermal power, and recirculation flow signals. Each OPRM channel can be individually tested for the operability of the OPRM scram functions by introducing test signals.

G. Environmental Considerations

See description for APRM in paragraph 7.6.2.2.4.G.

7.6.2.3 <u>Analysis</u>

7.6.2.3.1 Source Range Monitor System

A. Conformance to General Functional Requirements

The arrangement of the neutron sources and startup chambers in the reactor is shown on figure 7.6-2. This arrangement produces at least three counts per second in the SRM using the sensitivity noted in paragraph 7.6.2.2.1 and the design source strength at initial reactor startup. If the discriminator setting is adjusted to produce the specified sensitivity, the signal-to-noise count ratio is well above the 2:1 design basis for cold startup.

If the multiplication of one section of the core increases to put that section of the reactor on a 20-s period, the nearest SRM chamber shows an increase in count rate. In general, at least one detector indicates the change in multiplications.

Normal startup procedures ensure that withdrawal of control rods is distributed about the core to prevent excessive multiplication in any one section of the core. Hence, each SRM chamber can respond in some degree during the initial rod withdrawal. During the startup withdrawal, one of the four control rods adjacent to each SRM chamber and one control rod adjacent to each neutron source is

withdrawn before the reactor is critical. This procedure reduces source and detector shadowing and ensures increases in the detector signals as the core average neutron multiplication increases.

Examination of the sensitivity of the SRM detectors and their operating ranges of 10^6 counts per second indicates that the IRM is on scale before the SRM reaches full scale (figure 7.6-3). Further overlap is provided by partial retraction of the SRM chambers. Such retraction is possible only if the indicated SRM count rate remains above the rod block trip level (~ 10^2 counts per second), or if the IRM has been set to the third or any less sensitive (higher) IRM range.

B. Conformance to Specific Regulatory Requirements

There are no specific regulatory requirements of the SRM system.

7.6.2.3.2 Intermediate Range Monitor System

A. Conformance to General Functional Requirements

Section 7.2 evaluates the arrangement of redundant input signals to the RPS. The NMS trip input to the RPS and the trip channels used in actuating a NMS trip are of equivalent independence and redundancy to other RPS inputs.

The number and locations of the IRM detectors were analytically and experimentally determined to provide sufficient intermediate range flux level information under the worst permitted bypass or detector failure conditions. To verify this, a range of rod withdrawal accidents was analyzed. The most severe case assumes that the reactor is barely subcritical. One-fourth of the control rods plus one more rod were removed in the normal operating sequence (figure 7.6-11). The error or malfunction is removal of the control rod adjacent to the last rod withdrawn. This rod was chosen to maximize the distance to the second nearest detector for each trip system. It is assumed that the nearest detector in each RPS trip system is bypassed.

A scram signal is initiated when one IRM detector in each RPS trip system reaches its scram trip level. The neutron flux versus distance resulting from this withdrawal is shown on figure 7.6-12. Note that the second nearest detector in trip system B is further away than the second nearest detector in trip system A. The ratio of the neutron flux at this point to the peak flux is 1:4100. This detector reaches its high scram trip setting of 96% of full scale at a local flux ~ 3.3×10^8 Nv. At that time, the peak flux in the core is 1.35×10^{12} nv or 2.7% rated average flux. The core average power is 0.07% when scram occurs. For this scram point to be valid, the IRM must be on the correct range. To ensure that each IRM is on the correct range, a rod block is initiated any time the IRM is both downscale and not on the most sensitive (lowest) scale. A rod block is initiated if the IRM detectors are not fully inserted in the core unless the reactor mode switch is in the run position.

The IRM scram trips and the IRM rod block trips are automatically bypassed when the reactor mode switch is in the RUN position.

The IRM detectors and electronics have been tested under operating conditions and verified to have the operational characteristics described. They provide the level of precision and reliability required by the RPS safety design bases.

The IRM is the primary source of information as the reactor approaches the power range. Its linear steps (approximately a half decade) and the rod blocking features on both high flux level and low flux level require that all IRMs are on the correct range as core reactivity is increased by rod withdrawal. The SRM overlaps the IRM. The sensitivity of the IRM is such that the IRM is on scale on the least sensitive (highest) range with ~ 15% reactor power.

B. Conformance to Specific Regulatory Requirements

1. Compliance with Regulatory Guide 1.22 (February 1972)

   The portion of the IRM system that provides outputs to the RPS is designed to provide complete periodic testing of protection system actuation function as desired. This provision is accomplished by initiating an output trip on one IRM channel at any given time which will result in tripping one of the two RPS trip systems. Details are provided in NEDO-10139, subsection 2.2.8.

   Operator indication of IRM bypass is provided by indicator lamps as described in NEDO-10139, subsection 2.2.8.12.

2. Compliance with GDCs 13 and 22-24 of 10 CFR 50, Appendix A

   The IRM detectors and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

   Automatic initiation of RPS action, reliability, testability, independence, and separation were factored into the IRM design as required for protection systems.

3. Compliance with IEEE 279 (1971)

   The IRM design is shown to comply with the design requirements of IEEE 279 (1971) in subsection 2.2.8 of NEDO-10139.

4. Compliance with IEEE 323 (1971)

   Compliance with the requirements of IEEE 323 (1971) is discussed in section 3.11.

5. Compliance with IEEE 338 (1971)

   Compliance with IEEE 338 (1971) is discussed in subsections 2.2.8.9 and 2.2.8.10 of NEDO-10139.

6. Compliance with IEEE 344 (1971)

   Compliance with the requirements of IEEE 344 (1971) is discussed in section 3.10.

7. Compliance with 10 CFR 50, Appendix B

   The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.2.3.3 Local Power Range Monitor System

A. Conformance to General Functional Requirements

The LPRM provides detailed information about neutron flux throughout the reactor core. The number of LPRM assemblies and their distribution is determined by extensive calculational and experimental procedures.

Individual failed chambers can be bypassed. Neutron flux information for a failed chamber location can be interpolated from nearby chambers. Also, a substitute reading for a failed chamber can be derived from an octant-symmetric chamber; or an actual flux indication can be obtained by inserting a TIP to the failed chamber position. Each output is electrically isolated so that an event (grounding the signal or applying a stray voltage) on the reception end does not destroy the validity of the LPRM signal. Tests and experience attest to the ability of the detector to respond proportionally to the local neutron flux changes.[1]

B. Conformance to Specific Regulatory Requirements

There are no specific regulatory requirements of the LPRM subsystem. Because they form inputs to the APRM subsystem; however, a minimum number of LPRMs must be operable for each APRM and OPRM function (table 7.6-7).

7.6.2.3.4 Average Power Range Monitor System

A. Conformance to General Functional Requirements

Each APRM derives its signal from LPRM information. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design bases of the RPS. Four APRM channels allow one bypass and one undetected failure in each trip system and still satisfy the RPS safety design bases.

Figure 7.6-13 illustrates the ability of the APRM to track core power versus coolant flow, starting at 100% power and 100% flow to below the 65% flow point. Figure 7.6-14 illustrates the ability of the APRM to respond to control rod motion. The conditions for this are selected from the most restrictive case. The figure also shows a full withdrawal of a control rod from limiting conditions at rated power.

The flow-referenced APRM scram setpoint is adequate to prevent fuel damage during an AOO as demonstrated in section 15.2.

B. Conformance to Specific Regulatory Requirements

1. Compliance with Regulatory Guide 1.22 (February 1972)

   The portion of the APRM subsystem that provides outputs to the RPS is designed to provide complete periodic testing of protection system actuation functions as desired. Details are provided in NEDC-32410P-A. Operator indication of APRM bypass is provided by operator display assembly as described in NEDC-32410P-A.

2. Compliance with GDCs 13 and 20-24 of 10 CFR 50, Appendix A

   The APRM system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

   Automatic initiation of protection system action, reliability, testability, independence, and separation were factored into the APRM design as required for protection systems.

   The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

3. Compliance with IEEE 279 (1971)

   The APRM design is shown to comply with the design requirements of IEEE 279 (1971). NEDC-32410P-A provides clarification, where needed, regarding how the General Electric digital NUMAC PRNM retrofit system meets applicable requirements of IEEE 279-1971. The analysis applies to OPRM as well with clarification added where needed.

4. Compliance with IEEE 323 (1971)

   Compliance with the requirements of IEEE 323 (1971) is discussed in section 3.11.

5. Compliance with IEEE 338 (1971)

   Compliance with IEEE 338 (1971) is discussed in NEDC-32410P-A.

6. Compliance with IEEE 344 (1971)

   Compliance with the requirements of IEEE 344 (1971) is discussed in section 3.10.

7. Compliance with Regulatory Guide 1.152-1985

   The General Electric digital NUMAC PRNM retrofit project includes quality, verification and validation process controls in compliance with Regulatory Guide 1.152-1985. NEDC-32410P-A, Appendix A, includes a “compliance matrix” that correlates the requirements of Regulatory Guide 1.152-1985 to the implementing program.

7.6.2.3.5 Rod Block Monitor System

A. Conformance to General Functional Requirements

   Motion of a control rod causes the LPRMs adjacent to the control rod to respond strongly to the change in power in the region of the rod in motion. Because the MCPR cannot reach 1.07 until the control rod is withdrawn through greater than half its stroke, the highest rod block setpoint halts rod motion well before local fuel damage can occur. This is true even with the adjacent and nearest LPRM detector assemblies failed.

B. Conformance to Specific Regulatory Requirements

   1. Compliance with GDC 24 of 10 CFR 50, Appendix A

      The RBM provides an interlocking function in the control rod withdrawal portion of the CRD RMCS. This design is separated from the protective functions in the plant to ensure their independence.

      The RBM is designed to prevent inadvertent control rod withdrawal, given an imposed single failure within the RBM. One of the two RBM channels is sufficient to provide an appropriate control rod withdrawal block. In addition, the RBM is designed to meet appropriate protection system criteria acceptable to the NRC Staff as discussed in paragraph 7.6.2.2.5.

   2. Compliance with 10 CFR 50, Appendix B

      The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.2.3.6 Traversing Incore Probe Subsystem

A. Conformance to General Functional Requirements

An adequate number of TIP machines is supplied to ensure that each LPRM assembly can be probed by a TIP and that one LPRM assembly (the central one) can be probed by every TIP to allow intercalibration. The system has been field-tested in an operating reactor to ensure reproducibility for repetitive measurements. The mechanical equipment has undergone life testing under simulated operating conditions to assure that all specifications can be met. The system design allows semiautomatic operation for LPRM calibration and process computer use. The TIP machines can be operated manually to allow pointwise gamma flux mapping.

B. Conformance to Specific Regulatory Requirements

There are no specific regulatory requirements of the TIP system.

7.6.2.3.7 Oscillation Power Range Monitor

A. Conformance to General Functional Requirements

Each OPRM derives its signal from information obtained from the LPRM system. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design basis of the RPS. There are four OPRM channels with the RPS trip outputs from each routed to each of four OPRM two-out-of-four voter channels. Two voter channels are associated with each RPS trip system. This configuration allows one OPRM channel to be bypassed plus one failure while still meeting the RPS safety design basis.

APRM power (and simulated thermal power) is adjusted periodically based on heat balance to match true reactor power. This adjustment is made regularly at a rate sufficient to compensate for LPRM burnup and the related change in APRM values. This assures that the OPRM function will be enabled when the reactor is operating at a power level at which thermal-hydraulic instabilities might occur, nominally at power levels above 30%.

Recirculation coolant flow is also used to automatically bypass the OPRM trip when the reactor is operating at conditions of high core flow ($\leq$ 60%) when thermal-hydraulic oscillations are unlikely to occur. The setpoint for this automatic enable/disable function includes margin to accommodate variations in the relationship between recirculation drive flow and actual reactor core flow at operating conditions different from rated conditions.

The only OPRM algorithm for which safety credit is claimed is the period based algorithm. The setpoints for that algorithm are established using a methodology developed by the BWROG and plant specific fuel limits that provides adequate

margin in the actual setpoints to assure safety limits are not exceeded even in the presence of failed or bypassed LPRM detector signals.

Each OPRM channel provides an inoperative alarm when the quantity of operating OPRM cells is less than the required minimum. The OPRM subsystem provides the operator with front panel readouts showing the status of the OPRM subsystem and an oscillation pre-trip alarm when one of the instability algorithms (period based, amplitude based, or growth based) for an operable OPRM cell has exceeded user defined setpoints. The OPRM also provides an oscillation trip enable alarm that indicates when the reactor has reached the operating region where instability can occur and the oscillation trip output has been enabled (no longer bypassed). Together these readouts and alarms provide warnings to help assure that the operator will know when the plant is operating in a region or at a condition that may lead to an OPRM trip, and allow the operator to take appropriate action.

B. Conformance to Specific Regulatory Requirements

See discussion for APRM system in paragraph 7.6.2.3.4.B.

7.6.3 ESSENTIAL PROCESS RADIATION MONITORS

Radiation monitors are provided on liquid and gas lines where high-radiation levels would indicate a release to the environment that may exceed the limits indicated in sections 11.2 and 11.3. Radiation monitors are also provided on liquid and gas lines where radiation-level variations may indicate possible fuel or equipment failure. Process and effluent monitors not required for safety are discussed in section 11.4. The fission products and post-LOCA monitors are discussed in subsection 7.6.4. This subsection discusses the following three safety-related radiation monitors:

- Main steam line monitor.
- Reactor building ventilation exhaust monitor.
- Refueling floor ventilation exhaust monitor.

7.6.3.1 Main Steam Line Radiation Monitor

7.6.3.1.1 Design Basis

A. General Functional Requirements

This monitor detects gamma radiation levels from the main steam lines immediately downstream of the containment isolation valves. Alarms and a

recorder in the MCR provide the operator information with which to take appropriate action.

The occurrence of high count rates indicative of gross fission product release from the fuel incore generates an alarm and a trip to isolate the effluent line of the steam packing exhauster and drywell-to-torus interconnection line.

B. Specific Regulatory Requirements

This subsystem conforms to General Design Criteria 13 and 20 to 24 of 10 CFR 50, Appendix A; IEEE 279 (1971); IEEE 323 (1971); IEEE 338 (1971); and IEEE 344 (1971).

7.6.3.1.2 System Description

Basic monitor information is provided in table 11.4-1.

7.6.3.1.2.1 **System Identification.** This system meets all requirements of the RPS; i.e., seismic, quality control, and records.

7.6.3.1.2.2 **Initiating Circuits.** Four gamma-sensitive instrumentation channels monitor the gross gamma radiation from the main steam lines. The detectors are physically located near the main steam lines just downstream of the outboard MSIVs that are in the space between the primary and secondary containments. The detectors are geometrically arranged to detect significant increases in radiation level with any number of main steam lines in operation. Their location along the main steam lines allows the earliest practical detection of a gross fuel failure. Two of the channels are powered from one RPS bus, and the other two channels are powered from the other RPS bus.

Each monitoring channel consists of a gamma-sensitive ion chamber and a log radiation monitor. (See drawing no. H-26011). Capabilities of the monitoring channel are listed in table 11.4-1. Each log radiation monitor has three trip circuits. One upscale trip circuit is used to initiate isolation and alarm, and the other, lower, upscale trip circuit is used for an alarm. The lower alarm is set at a level sufficiently above background to preclude spurious alarms but low enough to provide the operator with notification that the level is increasing toward the upper setpoint. The upper alarm/trip level is established based on an analysis of the dose rate resulting from fission products released in the design basis control rod drop accident (CRDA). The setpoint provides for deenergization of the mechanical vacuum pump and closure of the mechanical vacuum pump line valve. The third circuit is a downscale trip that actuates an instrument trouble alarm in the MCR. The output from each log radiation monitor is displayed on a 6-decade meter in the MCR.

7.6.3.1.2.3 **Logic and Sequencing.** When a significant increase in the main steam line radiation level is detected, trip signals are transmitted to the off-gas control systems, steam

packing exhauster, and drywell-to-torus differential pressure valves. In the off-gas system, the vacuum pump is turned off and the mechanical vacuum pump line is shut. The steam packing exhauster, drywell-to-torus differential valves, and reactor recirculation pump loop sample valves are tripped and their associated pipe line is isolated.

The high-high radiation trip setting is selected so that a trip results from the fission products released at low-steam flow condition in the design basis CRDA. The setting is sufficiently above the background radiation level in the vicinity of the main steam lines that spurious trips are unlikely at rated power. However, the setting is low enough to trip on the fission products calculated to be released during the design basis CRDA.

The main line steam line radiation monitoring system consists of four instrumentation channels, which reduce the likelihood of an instrumentation malfunction that could inadvertently initiate isolation of the mechanical vacuum pump line and shutdown of the mechanical vacuum pump itself.

7.6.3.1.2.4 Redundancy. The number of monitoring channels provides the redundancy required. This redundancy is verified in the circuit description.

7.6.3.1.2.5 Testability. A built-in current source is provided with each log radiation monitor for test purposes. The operability of each monitoring channel can be routinely verified by comparing the outputs of the channels during power operation.

7.6.3.1.2.6 Power Source. The main steam line radiation monitor is powered from RPS buses 2A and 2B.

7.6.3.1.2.7 Environmental Considerations. This monitor is designed to operate in the environmental conditions expected in the main steam pipe chase during normal power operations.

7.6.3.1.2.8 Operational Considerations. The main steam line radiation monitor is designed to operate under all normal plant operating conditions. It is designed to withstand the environment that would accompany a gross fuel failure.

In the event of a high- or low-radiation-level trip within any of the channels, the system automatically activates the appropriate alarm annunciator in the MCR.

7.6.3.1.3 Analysis

7.6.3.1.3.1 Conformance to General Functional Requirements. The main steam line radiation monitoring system detects and promptly indicates a gross release of fission products from the fuel under any operation for any combination of main steam lines.

On detection of a gross release of fission products from the fuel, the system initiates appropriate alarm annunciators.

The description of the main steam line radiation monitors indicates how the safety design bases are satisfied. The system is capable of initiating safety action at the level of fuel damage resulting from the design basis rod drop accident. The amount of fuel damage and fission product release involved in this accident is relatively small. It is concluded that, for any situation involving gross fission product release, the main steam radiation monitoring system can provide prompt safety action.

7.6.3.1.3.2 Conformance to Specific Regulatory Requirements.

A. Regulatory Guide 1.22

The system conforms to Regulatory Guide 1.22 in that provisions have been built into the monitoring instruments to allow periodic testing of individual channels.

B. GDCs of 10 CFR 50, Appendix A

1. GDC 13

The system conforms to GDC 13 in that the instruments employed more than adequately cover the anticipated range of radiation under normal operating conditions with sufficient margin to include postulated accident conditions.

2. GDC 20

The system conforms to GDC 20 in that activation of the trip circuits results in alarm annunciator activation and, depending on the specific trip, a trip indication being sent to the RPS.

3. GDC 21

The system conforms to GDC 21 in that redundant circuits are an integral part of the system design.

4. GDC 22

The system conforms to GDC 22 in that the effects of natural phenomena and normal operation (including testing) do not result in loss of protection.

5. GDC 23

   The system conforms to GDC 23 in that the trip circuits associated with every channel have been designed specifically to fail safe in the event of loss of power.

6. GDC 24

   The system conforms to GDC 24 in that its manufacturing construction features ensure separation from the control system.

7. 10 CFR 50, Appendix B

   The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.3.2 Reactor Building Ventilation Exhaust Radiation Monitoring System

7.6.3.2.1 Design Basis

The reactor building ventilation radiation monitoring subsystem is designed to provide a clear indication to operations personnel and to initiate appropriate action to control the release of radioactive material to the environs when abnormal amounts of radioactive material exist in the reactor building ventilation exhaust.

7.6.3.2.2 System Description

The reactor building ventilation radiation monitoring system is shown on drawing no. H-26013 and specifications are given in table 11.4-1. The system consists of four independent channels. Each channel includes a Geiger-Muller-type detector and a combined indicator and trip unit. All equipment is located in the MCR except the detectors which are located in the reactor building ventilation exhaust duct. Each A, B, C, and D channel indicator and trip unit uses power supply K612A, K612B, K612C, and K612D, respectively.

Each channel has three trips. A high-high radiation trip, and a low-radiation trip are initiated by the monitor. A third trip, high radiation, comes from the recorder in its channel. The lower level alarm is set sufficiently above background to preclude spurious alarms but low enough to signal the operator that the radioactive level is increasing. The upper alarm is set at a level based on the fission products released as a result of an unspecified accident but equivalent to that level released in the design basis fuel-handling accident. The upper trip level provides for automatic closure of the ventilation system and initiation of the standby gas treatment system (SGTS).

If there are two-out-of-two upscale trips from either A and B, or C and D channels in the reactor building ventilation exhaust radiation monitors, the following will occur:

- Shutdown of the reactor building unit supply and exhaust fans.
- Closure of the reactor building vent supply and exhaust isolation valves.
- Startup of the SGTS.
- Closure of the primary containment purge and vent valves.

A. Power Sources

The RPS buses 2A and 2B supply power for the monitors.

B. Inspection and Testing

The monitors are installed so as to be readily accessible for inspection, calibration, and testing. The reactor building ventilation radiation monitoring system, the response of the reactor building heating and ventilation system, and the SGTS are routinely tested.

C. Environmental Considerations

The environmental considerations are discussed in section 3.11.

D. Operational Considerations

The physical location and monitoring characteristics of the reactor building ventilation radiation monitoring channels are adequate to provide detection capability for abnormal amounts of radioactivity in the reactor building ventilation and to initiate isolation. The redundancy and arrangement of channels are sufficient to ensure that no single failure can prevent isolation when required. The upscale trips meet the design requirements of IEEE 279 (1971).

The reactor building ventilation exhaust radiation monitoring subsystem is designed to operate between 0 and 60°C, and 20 and 98% relative humidity. It is designed to withstand the environment which would accompany a secondary containment high-radiation situation.

7.6.3.2.3 Analysis

7.6.3.2.3.1 **Conformance to General Functional Requirements.** The physical location and monitoring characteristics of the reactor building ventilation exhaust radiation monitoring channels are adequate to detect abnormal mounts of radioactivity in the reactor building atmosphere.

The upscale trips meet the design requirements of IEEE 279 (1971). During refueling operation (including criticality tests), the monitoring system acts as an ESF against the consequences of the fuel-handling accident and the CRDA. The response of the containment ventilation exhaust radiation monitoring system to the fuel-handling accident is presented in section 15.3.

7.6.3.2.3.2 Conformance to Specific Regulatory Requirements.

A. Regulatory Guide 1.22

The system conforms to Regulatory Guide 1.22 in that provisions which allow periodic testing of individual channels have been built into the monitoring instruments.

B. GDC of 10 CFR 50, Appendix A

1. GDC 13

This system conforms to GDC 13 in that the instruments employed more than adequately cover the anticipated range of radiation under normal operation conditions with sufficient margin to include postulated accident conditions.

2. GDC 20

The system conforms to GDC 20 in that activation of the trip circuit results in alarm annunciator activation and, depending upon the specific trip, a trip indication being sent to the reactor building ventilation system, the SGTS, and the reactor containment isolation valve dampers.

3. GDC 21

The system conforms to GDC 21 in that redundant circuits are an integral part of the system design.

4. GDC 22

The system conforms to GDC 22 in that the effects of natural phenomena and normal operation (including testing) do not result in loss of protection.

5. GDC 23

The system conforms to GDC 23 in that the trip circuits associated with each channel have been designed specifically to fail safe in the event of loss of power.

6. GDC 24

   The system conforms to GDC 24 in that its manufacturing construction features assume separation from the control system.

7. 10 CFR 50, Appendix B

   The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.3.3 Refueling Floor Ventilation Exhaust Radiation Monitoring System

7.6.3.3.1 Design Basis

A. General Functional Requirements

   This subsystem monitors radiation levels in the exhaust air from the refueling floor in the reactor building. Alarms and meters in the MCR provide the operators information with which to take appropriate action.

   This subsystem has a direct control function in that, if the radiation level exceeds a preset setpoint, a trip signal is generated that initiates the SGTS, trips and isolates the reactor building ventilation system, and closes the primary containment isolation valves.

B. Specific Regulatory Requirements

   This subsystem conforms to GDCs 13 and 20 through 24 of 10 CFR 50, Appendix A, and to IEEE 279 (1971), 323 (1971), 344 (1971), and 338 (1971).

7.6.3.3.2 System Description

7.6.3.3.2.1 System Identification. This monitor measures the activity from the spent-fuel pool, reactor well, dryer-separator pool areas, and the refueling floor area exhaust ducts before and after the air passes through the refueling floor ventilation filter which is in the exhaust line to the reactor building vent plenum. It is shown on drawing no. H-26012.

The fuel pool may contain gaseous activity due to mixing with the reactor coolant system during each refueling. Diffusion of this activity from the pool generates airborne activity which is swept into the spent-fuel pool area ventilation system. Gaseous activity released during a fuel-handling accident will also be swept into this ventilation system.

Twelve monitors are mounted on exhaust ducts upsteam of the refueling floor ventilation filters. These monitors have an automatic isolation function and are a designated safety system.

7.6.3.3.2.2 Equipment Design.

A. Circuit Description

System characteristics are given in table 11.4-1.

Each channel consists of a local sensor converter unit (gamma sensitive detector and associated circuitry), a radiation analyzer mounted in the MCR, and one channel of a recorder in the MCR.

There are three recorders provided. There are three trips on each channel, a high-high radiation, a high-radiation, and a low-radiation alarm. The alarm setpoint bases are the same as those for the reactor building ventilation exhaust monitors except that the upper alarm is based on the fission products released from the design basis fuel-handling accident.

For a two-out-of-two-upscale trip from either A and B or C and D channels in the refueling floor ventilation exhaust radiation monitors, the following will occur:

- Shutdown of the reactor building unit supply and exhaust fans.
- Closure of the reactor building vent supply and exhaust isolation valves.
- Startup of the SGTS.
- Closure of the primary containment purge and vent valves.
- Shutdown of the refueling floor vent, supply, and exhaust fans.
- Closure of the refueling floor vent supply and exhaust isolation valves.

A loss of power to the indicator trip units also initiates all the above actions because the trip circuit is designed to fail safe in the event of loss of power. Power is supplied from RPS bus 2A for one channel and from RPS bus 2B for the second channel.

7.6.3.3.2.3 Testability. Each channel is capable of being tested and inspected routinely.

7.6.3.3.2.4 Environmental Considerations. This system is designed to operate in environmental conditions more severe than those expected at the equipment location.

7.6.3.3.2.5 Operational Considerations. This system operates during all operating conditions and in high-radiation fields.

7.6.3.3.3 Analysis

7.6.3.3.3.1 **Conformance to General Functional Requirements**. This subsystem is designed with monitoring characteristics and physical location suitable to detect abnormal amounts of radioactivity in the room atmosphere over the fuel pool and in the surrounding areas.

This subsystem is designed to provide redundancy and arrangement of channels to ensure that no single failure can prevent isolation of the secondary containment when required.

The upscale trips of the fuel pool vent exhaust radiation monitors meet the design requirements of IEEE 279. During refueling operation, including criticality tests, the monitoring subsystem acts as an ESF against the consequences of the fuel-handling accident and the CRDA. The response of the refueling floor exhaust radiation monitoring system to the fuel-handling accident is presented in section 15.3.

7.6.3.3.3.2 **Conformance to Specific Regulatory Requirements.** These requirements pertain to the refueling floor exhaust radiation monitoring system.

A. Regulatory Guide 1.22

   The subsystem conforms to Regulatory Guide 1.22 in that provisions have been built into the monitoring instruments which allow periodic testing of individual channels.

B. GDC of 10 CFR 50, Appendix A

   1. GDC 13

      The subsystem conforms to GDC 13 in that the instruments employed more than adequately cover the anticipated range of radiation under normal operation conditions with sufficient margin to include postulated accident conditions.

   2. GDC 20

      The subsystem conforms to GDC 20 in that activation of the trip circuit results in alarm annunciator activation and, depending on the specific trip, a trip indication being sent to the reactor building ventilation system, the SGTS, and the reactor containment isolation system.

3. GDC 21

   The subsystem conforms to GDC 21 in that redundant circuits are an integral part of the system design.

4. GDC 22

   The subsystem conforms to GDC 22 in that the effects of natural phenomena and normal operation (including testing) do not result in the loss of protection.

5. GDC 23

   The subsystem conforms to GDC 23 in that the trip circuits associated with each channel have been design specifically to fail safe in the event of loss of power.

6. GDC 24

   The subsystem conforms to GDC 24 in that its manufacturing construction features assume separation from the control system.

7. 10 CFR 50, Appendix B

   The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.4 PRIMARY CONTAINMENT ATMOSPHERE MONITORS

The primary containment atmosphere is monitored for the following:

- Particulate and gaseous fission products in the drywell.
- Gamma radiation levels in the drywell and torus.
- H_2/O_2 concentration in the drywell.
- Temperature and pressure in the drywell.
- Pressure in the torus.
- Water temperature and water level in the torus.

The monitoring of these parameters provides the operator a continuous indication of conditions in the drywell and torus. These monitors provide no trip functions for safety systems; however, selected variables are alarmed in the MCR.

7.6.4.1 Fission Products Monitor

7.6.4.1.1 Design Bases

The fission products monitor has the following power generation design bases:

- Provide continuous radiation monitoring of the drywell atmosphere during reactor operation when the reactor is shutdown and when entry of personnel is required into that region.

- Provide an alarm if preset high limits are exceeded or if an instrument failure (offscale low) occurs.

7.6.4.1.2 System Description

The fission products monitor is described in paragraph 11.4.2.8.11.

7.6.4.2 Drywell and Torus Gamma Radiation Monitor

7.6.4.2.1 Design Basis

The drywell and torus gamma radiation monitors are designed to be operable before, during, and after a design basis event to measure gamma radiation levels in the drywell and torus.

7.6.4.2.2 System Description

The drywell and torus radiation monitoring system consists of two safety-related subsystems:

- A narrow-range.gross gamma detection system which monitors the drywell and the torus during normal operating conditions.

- A wide-range.gross gamma detection system qualified for use during and following a design basis event which monitors the drywell only.

Within each subsystem two-channel redundancy is provided.

The drywell and torus radiation monitoring system is further described in paragraph 11.4.2.8.12.

7.6.4.3 Hydrogen/Oxygen Analyzer

7.6.4.3.1 Design Basis

The primary containment hydrogen/oxygen monitor is designed to provide continuous indication and recording and alarms in the MCR of H_2/O_2 levels in the primary containment following a LOCA. The equipment is designed to remain functional during and after a design basis event and the applicable portions meet the requirements of rulemaking 10 CFR 50.49. The monitor conforms to GDC 64 and IEEE 279-1971.

7.6.4.3.2 System Description

The H_2/O_2 analyzer provides indication and recording in the MCR of the H_2/O_2 concentrations in the primary containment following a LOCA. H_2/O_2 concentrations in excess of preset limits are alarmed in the MCR. The H_2/O_2 analyzer provides no control function.

The H_2/O_2 analyzer is designed to operate reliably under postulated accident conditions for the equipment area as a result of a LOCA. (See section 3.11.) A commercial-grade oxygen analyzer is used to sample the drywell during normal operating conditions.

During normal plant operation, the H_2/O_2 analyzer is placed in the Standby mode of operation. The analyzer is automatically switched into the Analyze mode when the primary containment isolation system signal for the sample isolation valves is bypassed. The AC electrical power for the monitor is provided from essential DC inverters powered from the Station Battery Power System or essential AC buses.

The H_2/O_2 analyzer system is Seismic Category I and is discussed in paragraph 6.2.5.3.

7.6.4.3.3 Analysis

The H_2/O_2 analyzer is designed to monitor the primary containment following postulated accident conditions. The rate-of-flow of drywell atmosphere sample is sufficiently high to provide readings representative of the drywell atmosphere at that time. Monitored H_2/O_2 concentrations above a predetermined level are alarmed and annunciated in the MCR. The requirements of GDC 64 of 10 CFR 50 are met in that the monitor provides the means for monitoring the reactor primary containment atmosphere with indication and alarms in the MCR.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.4.4 Primary Containment Temperature Monitors

7.6.4.4.1 Design Bases

The primary containment temperature monitors are designed to meet the following safety design bases:

- Provide continuous monitoring of the drywell atmosphere temperature with a distributed arrangement of temperature sensors to secure representative temperature data.

- Provide continuous measurement of atmospheric temperature in the torus.

- Provide continuous measurement of water temperature in the torus.

- Remain functional during and after a design basis event.

A. Specific Regulatory Requirements

The primary containment temperature monitors are designed to conform to GDC 13 of 10 CFR 50 and Quality Assurance Criteria of 10 CFR 50, Appendix B.

7.6.4.4.2 System Description

A. Equipment Description

The primary containment temperature monitors measure drywell atmosphere temperature, torus atmospheric temperature, torus water temperature, and torus water average bulk temperature. A number of temperature sensors are located in the drywell, the torus atmosphere, and the torus water to ensure that representative temperature measurements are achieved. The monitored temperatures are continuously recorded on strip chart recorders. The primary containment temperature monitors have no control function, and their purpose is that of data acquisition. Because of the importance of securing these temperature data on occurrence of abnormal plant conditions, redundant temperature indicators and recorders are provided. The primary containment temperature-monitoring system is designed to meet Seismic Category I requirements.

B. Separation

Instrument control and power feed circuits of the two monitor subsystems are separate. Routing of power circuits is by separate paths and penetrations to preclude total loss of temperature monitoring capability by a single destructive event.

C. Power Sources

Operating power for the two sets of temperature monitors is supplied from separate essential buses to prevent total loss of monitoring capability on interruption of one bus.

D. Testability

To facilitate test and calibration of the temperature detectors, the resistance temperature detectors are removable from their working locations. The recorders are tested and checked for calibration by the standard technique of employing a standard resistance box after disconnection of the detection circuits.

E. Equipment Environment

The detectors, associated lead circuits, and recording instrumentation are of a design which provides reliable operation under the normal and postulated abnormal environmental conditions to which they are or could be subjected. The environmental conditions of specific plant areas are discussed in section 3.11.

F. Operational Considerations

The primary containment temperature monitor system operates continuously during operation of the reactor and secures recordings of the monitored temperatures. Should a LOCA occur, obtained recordings provide essential information about the temperatures monitored by the primary containment temperature monitor system.

Monitored temperatures are displayed on recorder charts in the MCR, making this information directly available to the operations personnel when the plant is in operation.

7.6.4.4.3 Analysis

A. Conformance to General Functional Requirements

The primary containment temperature monitoring system is designed to fulfill the design bases that are stated under paragraph 7.6.4.4.1.

B. Conformance to Specific Regulatory Requirements

The primary containment temperature monitoring system is designed to monitor continuously the temperature of the drywell atmosphere, torus atmosphere, and torus water.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the primary containment temperature monitoring system provides instrumentation to

obtain temperature measurements in the designated areas during normal operation, as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

The design of the primary containment temperature monitoring system includes multipoint recorders in the MCR on which the temperatures monitored are continuously recorded and displayed.

7.6.4.5 Primary Containment Pressure Monitor

7.6.4.5.1 Design Bases

A. General Functional Requirements

The primary containment pressure monitors are designed to meet the following safety design bases:

- Provide continuous measurement of the drywell atmospheric pressure.
- Provide continuous measurement of the torus atmospheric pressure.
- Provide trip logic, with adjustable setpoint, for high-pressure alarm.
- Remain functional during and after a design basis event.

B. Specific Regulatory Requirements

The primary containment pressure monitors are designed to meet GDC 13 of 10 CFR 50, Appendix A, and Quality Assurance Criteria of 10 CFR 50, Appendix B, for nuclear power plants.

7.6.4.5.2 System Description

7.6.4.5.2.1 Identification and Classification. The primary containment pressure monitoring system monitors the atmospheric pressure of the drywell and torus and records on chart recorders in the MCR. Drywell pressure is monitored by three different range transmitter and recorder instrument loops, while torus pressure is monitored by one instrument loop. The narrow-range drywell pressure range (-5/0/+5 psig) is recorded on a two-pen recorder with the other pen recording torus water level. The mid-range drywell pressure range (-10/0/+90 psig) is recorded on a two-pen recorder with the other pen recording torus pressure. The wide-range

drywell pressure range (0 to 250 psig) is also recorded on a two-pen recorder with the other pen recording drywell radiation.

The narrow range of the drywell pressure monitor permits detection of a change in drywell pressure resulting from a primary containment leak and provides for sensitive monitoring during normal operation of the plant. The mid- and wide-pressure ranges provide the capability to measure a pressure transient arising from a LOCA. Two complete and independent pressure monitoring subsystems make up the primary containment pressure monitoring system, one of which serves for backup. The pressure monitoring subsystem actuates an alarm and an annunciator upon increase of pressure to or beyond the setpoint level. This subsystem has no control function, and its purpose is that of data acquisition only.

Pressure transmitters/trip units used to initiate emergency core cooling system (ECCS) or provide inputs to the RPS are described in subsections 7.3.1 and 7.2.2.

The primary containment pressure monitoring system is classified as Seismic Category I.

A. Power Sources

   The electric power to each monitoring subsystem is supplied from an essential ac bus, except for the analog transmitter trip system (ATTS), which is described in section 7.8.

B. Separation

   Electrical circuits of the two identical pressure monitoring subsystems are routed separately to minimize vulnerability to total impairment of the monitoring subsystem by a single destructive event.

C. Testability

   To facilitate periodic checks of operation of this subsystem, provisions are incorporated to allow for in-place testing of the detectors and convenient removal for testing when the reactor is shut down.

D. Equipment Environment

   The equipment of the primary containment pressure monitoring system is designed to operate reliably under the normal and postulated abnormal conditions of the equipment areas. The environmental conditions of these areas are discussed in section 3.11.

E. The primary containment pressure monitoring system operates continuously during operation of the reactor, securing recordings of the pressures within the primary containment.

Should a LOCA occur, secured recordings provide information sought about transients in the pressure monitored by the primary containment pressure monitoring system.

Monitored pressures are displayed on recorder charts in the MCR as they are being recorded, making this information directly available while the plant is in normal operation.

7.6.4.5.3 Analysis

A. Conformance to General Functional Requirements

The primary containment pressure monitoring system is designed to fulfill the safety and power generation design bases stated in paragraph 7.6.4.5.1.

B. Conformance to Specific Regulatory Requirements

The primary containment pressure monitoring system is designed to continuously monitor atmospheric pressure in the drywell and in the torus. Trip logic is included, with adjustable setpoint, for actuation of an alarm and an annunciator on occurrence of above normal pressure conditions in either monitored region.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the primary containment pressure monitoring system has instrumentation which is provided, as required, for measurement and recording of pressure during normal operation, as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

The design of the primary containment pressure monitoring system includes chart recorders in the MCR on which the pressures monitored by the subsystem are continuously recorded and displayed.

7.6.4.6 <u>Torus Water Level Indicator System</u>

7.6.4.6.1 Design Basis

A. General Functional Requirements

The torus water level indicator system is designed to meet the following safety design bases:

- Provide measurement of water level in the torus over the maximum practical range.

- Provide trip logic, with adjustable high and low setpoints, for actuation of a MCR alarm when monitored water level is out of the allowable range.

- Remain functional during and after a design basis event.

B. Specific Regulatory Requirements

The torus water level indicator system is designed to meet GDC 13 of 10 CFR 50, Appendix A, and Quality Assurance Criteria of 10 CFR 50, Appendix B, for nuclear power plants.

7.6.4.6.2 System Description

The torus water level is continuously indicated and recorded in the MCR. The principal function of this monitor is to obtain data on water level in the torus on occurrence of a LOCA. The monitor also serves to indicate and record the water level in the course of normal operation of the plant; however, this is a supplementary function because the torus water level is controlled and level indication is necessarily provided in the MCR as part of the level controller. The torus water level indicator has no control function but incorporates provisions for actuation of an alarm and an annunciator on deviation of water level to or beyond the high or low setpoint limit (table 7.6-9).

The torus water level indicator system is classified Seismic Category I.

A. Power Sources

Operating electrical power for the monitor is supplied from separate essential DC inverters powered from the Station Battery Power System or essential AC buses.

B. Redundancy

Two identical level indicators and recorders comprise the torus water level indicator system, each of which is redundant and provides for backup service.

C. Actuated Devices

A high- and low-level alarm and annunciator are provided which are adjustable over the range of the instrument. The monitor provides no control function.

D. Separation

The two independent level indicators and recorders have signal and power lines routed separately to minimize vulnerability to impairment of both monitors by a single destructive event.

E. Testability

The monitor incorporates means to allow for complete testing during periods when the reactor is shutdown.

F. Environmental Considerations

The equipment is designed to operate reliably under the normal and postulated abnormal conditions to which the equipment would be exposed. The environmental conditions of the equipment areas are discussed in section 3.11.

G. Operational Considerations

The monitor is in continuous operation during operation of the reactor as well as during periods of shutdown, unless the equipment is taken out of service for test or maintenance purposes.

Should a LOCA occur, the recordings obtained provide essential information about the torus water level during the abnormal conditions.

The torus water level is continuously indicated and recorded in the MCR. Actuation of an alarm and an annunciator informs operations personnel of out-of-limits water level in the suppression chamber if such conditions occur because of a malfunctioning water level controller during normal operation of the plant (table 7.6-9).

7.6.4.6.3 Analysis

A. Conformance to General Functional Requirements

The torus water level monitor is designed to fulfill the design bases stated in paragraph 7.6.4.6.1.

B. Conformance to Specific Regulatory Requirements

The design provides for continuous monitoring of the water level in the torus. Included are provisions for high- and low-level alarm, with adjustable setpoints, to inform operations personnel of an out-of-limits water level condition of the pool.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the torus water level indicator constitutes instrumentation that is provided, as required, to monitor the torus water level during normal operation as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the same manner set forth in chapter 17.

The torus water level indicator design includes a recorder in the MCR on which the monitored level of the water pool is continuously recorded and displayed.

7.6.5 (Deleted)

7.6.6 REACTOR WATER CLEANUP SYSTEM

The purpose of the reactor water cleanup (RWC) system is to provide continuous processing of the reactor water so that the purity is maintained within specified limits. The system also provides the means for removal of reactor water. For example, to maintain reactor water level during startup, it is necessary to dump water due to swell.

7.6.6.1 Design Basis

The RWC system is not safety related. The power generation design bases are given in paragraph 5.5.8.1.

7.6.6.2 System Description

The RWC system and the circuitry used to protect the resin and the filter demineralizer are described in paragraph 5.5.8.2.

7.6.6.2.1 Identification and Classification

The purpose of the RWC system instrumentation and control is to provide protection for the system equipment from overheating and overpressurization and to provide the operator with information concerning the effectiveness of operation of the system.

This system is not safety related and all instrumentation components in the system are nonessential. The instrumentation is a standard industrial type for which performance has been proven by years of service throughout industry.

7.6.6.2.2 Circuit Description

The RWC system piping and instrumentation diagram is shown on drawing nos. H-26036 and H-26037. Drawing nos. H-24758 and H-24759 present the functional control diagram for the RWC system.

To prevent resins from entering the reactor recirculation system in the event of a filter-demineralizer resin support failure, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer is provided with a MCR alarm which is energized by high

differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units when necessary.

The RWC system is automatically isolated when signaled by any of the following occurrences:

- High temperature downstream of the nonregenerative heat exchanger to protect the ion exchange resins from deterioration due to high temperature.
- RPV water level 2 to protect the core in case of a possible break in the RWC system piping and equipment (subsection 7.3.2).
- SLCS actuation to prevent removal of the boron by one of the RWC system filter-demineralizers.
- RWC high system ambient temperatures (subsection 7.6.9).
- High temperature increase across the system ventilation ducts (subsection 7.6.9).
- High change in system inlet flow in comparison to the system outlet flow (subsection 7.6.9).

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided upstream of the RWC system and downstream of each filter-demineralizer unit for continuous indication and recording of system conductivity. High conductivity is annunciated in the MCR. The influent sample point is also used as the normal source of reactor coolant samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

7.6.6.2.3 Testability

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

7.6.6.2.4 Supporting Systems

The RWC instrumentation is fed from the plant instrumentation bus. No backup power source is necessary since the RWC system is not a safety-related system. The RWC instrumentation is arranged in groups or circuits, and each such circuit is protected by a suitable fuse. Thus, a short circuit within the system has only a local effect which can be easily corrected without interrupting reactor operation.

7.6.6.2.5 Equipment Environment

The RWC system is not required for safety nor is it required to operate after the DBA. The RWC system is required to operate in the normal plant environment for power generation only.

RWC control instrumentation located in the RWC equipment area is subject to the environment described in section 3.11.

7.6.6.2.6 Operational Considerations

The RWC system instrumentation and control are not required for safe operation of the plant. They provide a means of monitoring system parameters and protecting the system.

7.6.6.3 <u>Analysis</u>

A. Conformance to General Functional Requirements

Relief valves protect the RWC system from overpressurization. Two temperature switches upstream of the filter-demineralizer unit protect the ion exchange resin from high temperature. One switch activates an alarm when the water temperature reaches 130°F.

A second switch provides a signal at 140°F to close the isolation valve which subsequently trips the RWC pumps. The isolation valves also close automatically on signals shown on drawing nos. H-24758 and H-24759. The pumps also trip on high cooling water temperature or low discharge flow.

A high differential pressure across a filter-demineralizer or its discharge strainer automatically closes the unit outlet valve after sounding an alarm. The holding pump starts whenever there is low flow through a filter-demineralizer. The precoat pump does not start when the level in the precoat tank is low.

Sampling stations are provided for obtaining reactor water samples from the entrance and exit of both filter-demineralizers. The effluent conductivity must be maintained below 0.1 μmho, its pH factor between 6.5 and 7.5, and the amount of insolubles below ten parts per billion.

The system instrumentation and control for flow, temperature, and conductivity is recorded and/or indicated on a panel in the MCR. Instrumentation and controls for backwashing and precoating the filter-demineralizers are on a local panel in the reactor building. Alarms are sounded in the MCR to alert the operator to abnormal conditions.

The RWC system is controlled by the operator from the MCR.

A list of RWC system annunciators is given in table 7.6-10.

B. Conformance to Specific Regulatory Requirements

Since the RWC system is not a safety-related system, no specific regulatory requirement is applicable.

7.6.7 RPV POWER GENERATION INSTRUMENTATION

Drawing nos. H-26000, H-26001, and H-26189 show the instrument numbers, arrangements of the sensors, and sensing equipment used to monitor the RPV conditions. Because the reactor vessel sensors used for safety systems, ESFs, and control systems are described and evaluated in other portions of this document, only the sensors that are not required for those systems are described in this subsection.

7.6.7.1 Design Basis

The power generation design basis for the RPV instrumentation consists of maintaining proper operating conditions. To maintain proper operating conditions, the RPV instrumentation is designed to provide the operator with sufficient indication of RPV temperature, reactor core flowrate, RPV water level, RPV pressure, and nuclear system leakage. These instruments augment existing information so that the operator can start up, operate, shut down, and efficiently service the reactor.

7.6.7.2 System Description

7.6.7.2.1 Identification and Classification

The purpose of the RPV instrumentation is to monitor the following RPV operating parameters during plant operation:

- RPV temperature.
- RPV water level.
- Jet pump differential pressures and flows.
- RPV pressure.
- RPV head seal leak detection.
- Safety relief valve seat leak detection.
- Steam temperature.

- Feedwater temperature.

- Safety relief valve position indication.

The systems and instruments discussed in this subsection are designed to operate under normal and peak operating conditions of system pressures and ambient pressures and temperature; however, no special industry classifications are imposed on these instruments.

7.6.7.2.2 Equipment Design

The instrument-sensing lines to the various pressure and level sensors slope downward from the vessel to the instrument rack a minimum of 1/8 in./ft (including allowance for piping sag) so that air traps are not formed and the instrument lines are self-venting back to the reactor vessel. The instrument tubing installed by ATTS is sloped 1/4 in./ft, unless otherwise technically justified.

7.6.7.2.3 Circuit Description

7.6.7.2.3.1 **RPV Temperature.** The RPV temperature is determined on the basis of reactor coolant temperature. Temperatures needed for operation and for compliance with the Technical Specifications operating limits are obtained from one of several sources depending on the operating condition. During normal operation, RPV pressure and/or the inlet temperature of the coolant in the recirculation loops can be used to determine the RPV temperature. Below the operating psia of the resistance temperature detectors in the recirculation loop, the RPV pressure is used for determining the temperature. Below 212°F, the vessel coolant temperature and the vessel temperature are reasonably well shown by the RWC system inlet temperature. These three sources of input are most conveniently available from the process computer. During normal operation, vessel thermal transients are limited via operational constraints on parameters other than temperature.

RPV thermocouples are provided as a means of observing vessel metal surface temperature behavior in response to changes in vessel coolant temperature during startup and during power operation testing. Indications based on the thermocouples are not used for controlling the rate of heating or cooling or limiting the vessel thermal stresses.

7.6.7.2.3.2 **RPV Water Level.** The RPV water level instrumentation systems are discussed in other sections as follows:

- RPV water level instrumentation that initiates a reactor trip is discussed in paragraph 7.2.2.2.

- RPV water level is maintained by the feedwater control system (subsection 7.7.3).

The RPV water level system that pertains to this section is used to monitor in the MCR the RPV water level during the shutdown condition when the reactor system is flooded for maintenance and head removal. The water level instrumentation design is the condensate chamber reference leg type that is not compensated for change in density. The vessel condition that provides accurate water level information is 0.0-psig pressure and ambient temperature. The range of the instrument is from the bottom of the feedwater control operating range to a level over the top of the RPV head. (Reference drawing nos. H-26000, H-26001, and H-26189 for specific values at which alarms and safety actions are initiated.)

7.6.7.2.3.3 Reactor Core Hydraulics. Drawing nos. H-26000, H-26001, and H-26189 show the flow instruments, differential pressure instruments, and recorders provided so that the core coolant flowrates and the hydraulic performance of RPV internals can be determined.

The differential pressure between the throat of each jet pump and of the core inlet plenum is measured and indicated in the MCR. Four jet pumps, two associated with each recirculation loop, are specially calibrated. They are provided with pressure taps in the diffuser sections. The differential pressure measured between the diffuser tap and the throat tap allows precise flow calibration using the jet pump prototype test performance data for each of the calibrated jet pumps. The flowrates through the remaining jet pumps are calculated from the flows shown by the four calibrated jet pumps. The flowrates through the jet pumps associated with each recirculation loop are summed to provide MCR indication of the core flowrate associated with each recirculation loop (drawing nos. H-26000 and H-26001). Total flows for both loops are summed and recorded in the MCR to indicate the total flow through the core. During operation of a single recirculation loop, total core flow indication is derived by subtracting the reverse flow signal from the forward flow signal of the active jet pumps. This function is provided automatically any time a single recirculation pump is operating.

A differential pressure transmitter indicates core plate pressure drop by measuring the pressure difference between the core inlet plenum and the space just above the core support assembly. The instrument sensing line used to determine the pressure in the core inlet plenum is the same line used for injection of the standby liquid from the SLCS. An instrument sensing line is provided for measuring pressure above the core support assembly. The differential pressure across the core plate is indicated and recorded in the MCR.

A differential pressure transmitter indicates the jet pump pressure head by measuring the difference between the pressure above the core and the pressure below the core plate.

This instrumentation permits the determination of total core flow in two ways. The first method is the readout of the summed flow measurements from all the jet pumps. The second method includes the use of jet pump prototype performance data, jet pump differential pressures, and core plate differential pressure. A temporary correlation can also be made to define core flow as a function of reactor operating power level and the readout of the head developed by the jet pump. This correlation is of a temporary nature, because it changes with a fixed core arrangement over a period of time as a result of crud buildup on the fuel. The MCR flowrate readouts of the specially calibrated jet pumps can be used to cross check the flowrate readouts of all the other jet pumps. A discrepancy in the cross-checks is reason enough to check local flow indications.

7.6.7.2.3.4 RPV Pressure. Pressure switches, indicators, and transmitters detect RPV internal pressure from the same instrument lines used for measuring RPV water level.

The following list shows the subsections in which the RPV pressure measuring instruments are discussed:

A. Pressure transmitters/trip units for initiating a scram are discussed in paragraph 7.2.2.2.

B. Pressure transmitters/trip units used for the high-pressure coolant injection (HPCI) and core spray (CS) systems, the low-pressure coolant injection (LPCI) mode of the residual heat removal system, and the automatic depressurization system (ADS) are discussed in subsection 7.3.1.

C. Pressure transmitters and recorders used for feedwater control are discussed in subsection 7.7.3.

D. Pressure transmitters used for wide-range pressure recordings are discussed in paragraph 7.5.1.3.2.

7.6.7.2.3.5 RPV Head Seal Leak Detection. A pressure between the inner and outer head seal rings is sensed by a pressure switch. If the inner seals fail, the pressure at the pressure switch is the RPV pressure, and the pressure switch trips, sounding an annunciator in the MCR. The plant continues to operate with the outer seal as a backup, and the inner seal can be repaired at the next outage when the head is removed. If both the inner and outer head seals fail, the leak is detected by an increase in drywell temperature and pressure. This system is part of the leak detection system (LDS) which is described in subsection 7.6.9.

7.6.7.2.3.6 Safety Relief Valve Seat Leak Detection. Thermocouples are located near the discharge of the safety relief valve seat. The temperature signal goes to a multipoint recorder with an alarm. The alarm will be activated by any temperature in excess of a set temperature signaling that one of the safety relief valve seats has started to leak. This system is part of the LDS.

7.6.7.2.3.7 Other Instruments.

A. The steam temperature is measured at the steam manifold and is recorded in the MCR.

B. The feedwater temperature is measured and transmitted to the MCR.

7.6.7.2.3.8 Safety Relief Valve Position Indication. Safety relief valve position indication is provided by two indirect methods. One is by monitoring downstream pressure and the second by monitoring downstream temperature (paragraph 7.6.7.2.3.6).

Pressure monitoring is accomplished by the use of pressure switches. These switches are arranged in two groups. The first group consists of 11 pressure switches operating control room relays which are powered from the Class 1E 125-V-dc Division I power supply. The second group consists of 11 pressure switches operating control room relays which are powered from the Class 1E 125-V-dc division II power supply.

The relays powered from division II provide signals to the plant annunciation system, MCR panel indication, computer system, and low-low set (LLS) logic. The relays powered from division I provide signals to the LLS logic. These two groups have physical separation and cables are routed through respective divisional raceway.

Temperature monitoring on each safety relief valve is by a copper constantan thermocouple connected to a common temperature recorder in the MCR. Power for this recorder is fed from the emergency 120-V-ac division II instrument bus. The recorder signals the plant annunciation on high temperature.

Figure 7.6-15 shows a simplified schematic of the safety relief valve position indication system.

7.6.7.2.4 Testability

Pressure, differential pressure, water level, and flow instruments are located outside the drywell and are piped so that calibration and test signals can be applied during reactor operation.

7.6.7.2.5 Environmental Considerations

As part of the LLS logic, the safety relief valve tailpipe pressure switches are required for a small- or intermediate-sized LOCA and are qualified for the expected accident environment inside the drywell.

7.6.7.2.6 Operational Considerations

7.6.7.2.6.1 Normal. The RPV instrumentation discussed in this subsection is designed to augment the existing information from the ESFs so that the operator can start up, operate at power, shut down, and efficiently service the RPV. None of this instrumentation is required to initiate any ESF.

7.6.7.2.6.2 Operator Information. The following information is available to the operator:

A. Selected RPV thermocouples are recorded on recorders in the MCR.

B. The shutdown flooding water level is indicated in the MCR.

C. The flow for each of the four calibrated jet pumps is indicated in the MCR.

D. The differential pressure for all the jet pumps (calibrated and uncalibrated) is indicated in the MCR and relay room.

E. The recirculation core flow that is generated by each recirculation loop is indicated in the MCR.

F. The total core flow is recorded by one channel of a multichannel recorder in the MCR. Another channel records the core plate differential pressure.

G. The jet pump developed head is indicated in the MCR.

H. RPV pressure is indicated at two local racks by a pressure gauge.

I. The reactor head seal LDS activates an annunciator when an inner reactor head seal fails.

J. The discharge temperatures of all the safety relief valves are shown on a multipoint recorder in the MCR. Any temperature in excess of setpoint turns on an annunciator indicating that a safety relief valve seat has started to leak.

7.6.7.2.6.3 **Setpoints.** The annunciator alarm setpoints for the reactor head seal leak detection, safety relief valve seat leak detection, and feedwater corrosion product monitor are set so the sensitivity to the variable being measured provides adequate information.

Drawing no. H-26189 includes a chart showing the relative and specific water levels at which various automatic alarms and safety actions are initiated. Each of the listed actions is described and evaluated in the subsection of this report where the system involved is described. The following list tells where various level-measuring components and their setpoints are discussed:

A. Level transmitters/trip units for initiating a scram are discussed in paragraph 7.2.2.2.

B. Level transmitters/trip units for initiating primary containment or vessel isolation are discussed in subsection 7.3.2.

C. Level transmitters/trip units used for initiating HPCI, LPCI, CS, ADS and the level transmitters/trip units to shut down the HPCI pump drive turbine are discussed in paragraph 7.3.1.2.

D. Level transmitters/trip units to initiate reactor core isolation cooling (RCIC) and the level switches to shut down the RCIC pump drive turbine are discussed in paragraph 7.4.1.2.

E. Level trips to initiate various alarms and trip the main turbine, and the motor- or turbine-driven feed pumps are discussed in subsection 7.7.3.

7.6.7.3 Analysis

The RPV instruments and systems discussed in this subsection are designed to augment the existing information from the ESF systems so that the operator can start up, operate at power, shut down, and service the reactor system efficiently. None of this instrumentation is required to initiate any ESF system; consequently, no specific regulatory requirements are imposed on the RPV power generation instrumentation.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in chapter 17.

7.6.8 PROCESS COMPUTER SYSTEM (HNP-1 AND HNP-2)

7.6.8.1 Power Generation Objective

The objectives of the process computer system are to:

A. Provide a rapid and accurate determination of core thermal performance.

B. Provide data analysis, reduction, accounting, and logging functions.

C. Support communication with and provide a logging function for the rod worth minimizer (RWM).

7.6.8.2 Power Generation Design Bases

The process computer system meets the following power generation design bases:

A. The process computer is designed to take reactor process and incore data and produce current state and predicted core performance information to support efficient plant operation. The system produces plant data logs and color graphic displays which permit accurate assessment of core thermal performance.

B. The process computer system performs periodic core performance calculations and provides appropriate alarms that are based on established core operating limits and aid the operator in ensuring that the core is operating within acceptable limits at all times, especially during periods of power level changes.

C. The process computer provides automatic and on-demand logs and output files that contain data which may be used to display incoming process data and calculated results in a number of ways. Specific examples of the use of this logging capability are support of some types of plant performance optimization efforts, assisting in fuel and other core component exposure evaluations, and tracking of specific process variables.

D. The process computer provides the capability to transmit control rod sequences to the RWM. The process computer receives rod position data from the RWM.

E. The process computer provides alarm logging of selected significant status changes for nuclear system alarm inputs as an aid in general operation of the plant. Portions of the process computer alarm logging functions are performed by the SPDS.

F. The process computer provides post-trip and scram logging that presents selected process and contact actuated input data in sequence for periods before and after a trip/scram to assist in determining the cause of the trip/scram. Portions of the process computer post-trip and scram logging functions are performed by the SPDS.

7.6.8.3 System Description

7.6.8.3.1 System Objective

The basic objectives of the process computer system are discussed in paragraph 7.6.8.1.

7.6.8.3.2 System Design Bases

The process computer system design bases are discussed in paragraph 7.6.8.2.

7.6.8.3.3 Power Sources

The power for the process computer system is supplied from the uninterruptible ac power system. (Reference HNP-1-FSAR subsection 8.7.2 and HNP-2-FSAR paragraph 8.3.1.1.4.C.)

7.6.8.3.4 Process Computer System Components

7.6.8.3.4.1 Central Processors. The process computer contains two central processors, each capable of receiving data from the RWM communication functions and performing all vital functions in the event of a failure of one of the processors. Only the secondary processor can send sequences to the RWM under normal conditions. The processors are supported by main memory, hard disk storage devices, and communications equipment between the processors and peripherals. The processors are located in the computer equipment room.

7.6.8.3.4.2 System Peripherals. Peripheral equipment includes video terminals and printers distributed across the plant site and plotters, disk, and magnetic tape units located in the computer room.

7.6.8.3.4.3 Data Acquisition Equipment. Data acquisition equipment includes analog and digital input cards, card chassis to sample and digitally convert the signals from each card channel, and data formatters which are connected via fiber optics to each card chassis. The data formatters are also connected via fiber optic links to the RWM. The data formatters collect plant data at rates from once per second to 1000 times per second and transmit that data to the central processor for immediate processing and storage.

7.6.8.3.4.4 Operator Workstation. During routine operation the operator uses a workstation located in the MCR to enter requests for information and functions into the computer and to view color graphic displays. The color graphic display and printer outputs permit the operator to adequately communicate with the process computer.

7.6.8.3.5 Inspection and Testing

The process computer system performs diagnostic checks to determine the operability of certain portions of the system hardware, and it performs internal checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

7.6.8.3.6 Environmental Considerations

Process computer system equipment located in the computer room and MCR is designed to withstand the environments in these areas. The plant environment in these areas is given below:

	Parameter	Design
MCR	Temperature	≤ 79°F
	Relative Humidity	≤ 75%
Computer Room	Temperature	≤ 76°F
	Relative Humidity	≤ 50%

7.6.8.3.7 Reactor Core Performance Considerations

7.6.8.3.7.1 Power Distribution Evaluation. The local power density is calculated in 24 or 25 axial nodes or approximately every 6-in. segment for every fuel assembly, using plant inputs of pressure, temperature, flow, LPRM levels, control rod positions, and the calculated fuel exposure. The system uses a coupled diffusion theory nuclear thermal-hydraulic model adapted to TIP and LPRM measurements to provide three-dimensional simulation of BWR performance. The accuracy of the modeling is enhanced by the application of adaptive algorithms which conform results to incore neutron flux measurements. The reactor power, moderator void, and flow distributions are calculated. From these, other parameters such as

margin to thermal limits, fuel exposure, and Preconditioning Interim Operating Management Recommendations (PCIOMR) envelope data can be determined.

7.6.8.3.7.2 **Core Monitoring.** A data snapshot is taken every 15 s. Core monitoring is designed to automatically track current reactor parameters on a periodic basis, on demand or triggered by exceeding prespecified limits and changes in core power, core flow, or control rod pattern. This provides a near-continuous evaluation of core thermal limits. Execution of a fast monitoring case provides estimates of margins to thermal limits. Regular monitoring provides a more accurate monitoring case. The range of surveillance and the rapidity with which the system responds to reactor changes permit more rapid power maneuvering with the assurance thermal operating power limits are not exceeded.

7.6.8.3.7.3 **CROSSFLOW™ System Addition for Appendix K Uprate (Reactor Heat Balance Power Measurement Uncertainty)**. The NRC amended 10 CFR 50, Appendix K (ECCS Evaluation Models) which gave licensees the option to maintain a 2% power measurement margin or apply a reduced margin. If a licensee elects to apply a reduced margin, a rated thermal power level increase can be requested that credits the reduction in the power measurement uncertainties. The revised Appendix K rule has an effective date of July 31, 2000. Utility uprates applying this rule change are referred to as Appendix K Uprates, Measurement Uncertainty Recapture Uprates, Calorimetric Uprates, Thermal Power Optimization (TPO), or Mini-Uprates.

Plant Hatch was previously licensed to operate at a maximum rated thermal power (RTP) of 2763 MWt. This power level was supported by a number of analyses and evaluations performed with an RTP uncertainty of 12%, either through 10 CFR 50 Appendix K or RG 1.49. By applying a reduced thermal power uncertainty to those analyses, Plant Hatch was granted an increase in RTP by 1.5% to 2804 MWt and remains within the bounds of these specific analyses. The improvement in power measurement uncertainty and the associated power increase was accomplished by installing an advance main feedwater flow measurement CROSSFLOW™ system.

The CROSSFLOW™ system provides a more accurate measurement of feedwater flow than what was previously used for the core thermal power (CTP) calculation. Combustion Engineering topical report CENPD-397-P-A documents the theory, design, and operating features of the CROSSFLOW™ system and its ability to achieve increased flow measurement accuracy. The CROSSFLOW™ systems installed and commissioned at Hatch are capable of providing a measured feedwater mass flow to within 0.42% for both units. This bounding mass flow uncertainty was used to calculate the total power measurement uncertainty required by Appendix K to < 0.5%. The reduced power measurement uncertainty alleviates the need for the 2% power margin originally required by Appendix K, thereby allowing an increase in the RTP for additional electrical generation.

The Unit 1 and Unit 2 CROSSFLOW™ systems are each comprised of an ultrasonic feedwater flow measurement system (UFM) and an ultrasonic feedwater temperature measurement system (UTM). Each unit consists of UFM devices installed on the “A” and “B” feedwater that provide corrections to the respective feedwater flow venturi measurement. The UTMs are used to correct the RTD-based feedwater temperature which, in turn, provides a means to correct the

feedwater mass flowrate. Each flow measurement device is composed of eight nonintrusive flow transducers mounted on the feedwater piping and a set of temperature sensing transducers connected via coax cable to a remote panel that acts as a data acquisition system and a viewing system.

The CROSSFLOW™ systems are operated continuously, where process information is provided to and communicated from the plant process computer real-time via a process computer interface. The primary feedwater flow measurement is made with the feedwater flow venturi (1C32-N001 A&B, 2C32-N001 A&B) and the venturi measurements are automatically corrected within the plant process computer algorithm and communication layer. Process and correction limits are established within each system's online UFM venturi correction computer (OVCC) and the UTM online temperature correction computer (OTCC). These limits are established based on the instrument uncertainty analysis quality assurance (QA) calculation. The effects of corrosion and the associated changes in the acoustic path of the transducers are monitored continuously. Critical and noncritical limits are logged by the process computer and, if a critical limit is exceeded, the process computer will use the "last good" correction factor for no more than 72 h as allowed by the Measurement Recapture Power Uprate license amendment. If the out-of-limit condition exists for more than 72 h, the process computer will change the CROSSFLOW™ feedwater venturi mass flowrate correction factor to "1", thereby removing the CROSSFLOW™ system input from the reactor heat balance calculation. Changes to the OVCC and OTCC limits require review of, and corroboration with, other power dependent plant indications prior to implementation.

Neither the process computer nor the CROSSFLOW™ system is safety-related, but are considered tools which the reactor operator may use to more efficiently perform the power adjustments and limits monitoring functions. The CROSSFLOW™ systems have no control function and are not an integral part of the feedwater control system instrumentation.

7.6.8.3.7.4 **LPRM Calibration.** Gamma flux level and position data from the TIP equipment are input to the system. The data are evaluated and the gain adjustment factors (GAFs) determined. The GAF is the gain adjustment and exposure correction factor by which the LPRM amplifier gains can be altered to compensate for exposure-induced sensitivity loss. The LPRM amplifier gains shall not be physically altered without obtaining the necessary tip traces from the TIP subsystem. The GAF computations help to indicate to the operator when such a calibration procedure is necessary.

7.6.8.3.7.5 **Fuel Exposure.** Using the power distribution data and fuel density, a distribution of fuel exposure increments from the previous power distribution calculation is used to update the distribution of cumulative fuel exposure distribution. Each fuel bundle is identified by batch and location, and its exposure is stored for each of the axial segments used in the power distribution calculation. These data are printed out on demand by the operator.

7.6.8.3.7.6 **Control Rod Exposure.** Exposure increments are determined periodically for each 6-in. segment and edited by segments of one-quarter length section of each control rod.

The corresponding cumulative exposure totals are periodically updated and printed out on demand by the operator.

7.6.8.3.7.7 LPRM Exposure. The exposure increment of each LPRM is determined periodically and is used to update both the cumulative ion chamber exposures and the correction factors for exposure-dependent LPRM sensitivity loss. These data are printed out on demand by the operator.

7.6.8.3.7.8 Isotopic Composition of Exposed Fuel. The system provides online capability to determine monthly and on-demand isotopic composition for each fuel bundle, each batch, or all bundles in the core. This evaluation consists of computing the weight of neptunium 237, uranium 235, 236, and 238, and plutonium 238 through 242 isotopes as well as the total uranium and total plutonium content. The method of analysis consists of relating the computed fuel exposure and average void fraction for the fuel to predetermined fuel type specific isotopic characteristics. The output report is demandable by the operator.

7.6.8.3.7.9 RWM Communication Function. The RWM communication function transmits and receives data from the RWM which transmits control rod position data continuously to the process computer once per second. The RWM also transmits problem messages (control rod data not received, control rod data invalid, RWM self test diagnostic failure) to the process computer for logging. The process computer logs any interruption in transmission of control rod data from the RWM by logging appropriate transmission problem messages.

The process computer contains RWM sequence loading software for transmission of control rod movement sequences to the RWM.

7.6.8.3.7.10 Monitoring, Alarm, and Logging Functions

A. Monitoring Function

The process computer acquires and stores the values of all its plant inputs at rates ranging from once per second to 1000 times per second. Special digital cards allow points used for sequence of events analysis to be monitored for state change every 0.333 milliseconds, effectively making the resolution of these points three times faster even though their transfer rate to the process computer is still 1000 times per second at best. All stored plant data can be analyzed by all the analysis software functions on the process computer. The latest real-time data are used for all periodic and on-demand programs when they execute.

B. Alarm Function

The process computer is capable of checking each analog input variable against two types of limits for alarming purposes:

1. Process alarm limits as determined by the computer during computation or as defined by a fixed value. Several levels of alarming can be defined (e.g., prealarm and alarm).

2. Low and high reasonableness limits of the analog input signal levels.

   The process computer is capable of checking each digital input variable for an input change to a predefined alarm state.

   Alarm annunciation consists of a printed message, a color change on an alarm status tag on color graphic displays, or an alphanumeric message on other displays. Variables returning to normal are signified similarly. Alarms are acknowledged via a function key stroke from the reactor operator console.

C. Logging Function

The process computer generates operational, performance, and event logs based on real-time, historical, or calculated values. The system also generates diagnostic event messages and user action messages, as required.

The process computer automatically logs the values of up to 144 selected variables for preselected periods immediately preceding and following reactor scrams or specified trips.

Selected digital inputs are implemented to provide for logging the sequence of contact closure or opening on the alarm output device. Sequence of contact change events are sequentially differentiated and chronologically resolved to within 0.333 milliseconds for some selected inputs, and logged with point ID, point descriptions, and time of occurrence.

7.6.8.4 Analysis

A. Conformance to General Functional Requirements

The process computer system is designed to provide the operator with certain categories of information as defined in the system description in paragraph 7.6.8.3 and to supplement procedural requirements for control rod manipulation during reactor startup and shutdown. This system augments existing information from other systems so that the operator can start up, operate at power, and shut down efficiently. This system is not required to initiate any ESF or safety-related system.

B. Conformance to Specific Regulatory Requirements

The process computer system has no specific regulatory requirements.

7.6.9 LEAK DETECTION SYSTEM

7.6.9.1 Design Bases

The LDS design bases are presented in subsections 5.2.7 and 9.3.3.

7.6.9.2 System Description

A description of LDS features are presented in subsections 5.2.7 and 9.3.3. General instrumentation information on the LDS is presented in table 7.6-11. This section discusses the various instrumentation and controls incorporated for leakage detection.

As described in subsections 5.2.7 and 9.3.3, the LDS detects leaks through the application of the following techniques:

- Sensing excess flow in selected process piping through utilization of differential pressure instrumentation and flow nozzles.
- Sensing pressure and temperature changes inside the primary containment.
- Monitoring ambient temperature in selected areas outside the primary containment.
- Monitoring supply and exhaust air differential temperatures in selected spaces outside the primary containment.
- Monitoring the reactor building closed cooling water (RBCCW) system surge tank level.
- Monitoring fill and pumpdown rates of the reactor building and drywell floor and equipment drain sumps.
- Monitoring RPV water level.
- Monitoring drywell cooling unit chilled water differential temperature.

A summary of isolation/alarm of systems monitored and the LDS methods employed is presented in table 5.2-6.

A. Testability

The correct operation of each sensor and logic associated with the LDS is verified for the proper operation during the LDS preoperational test and during inspection tests which are provided for the various components as they apply during plant operation.

Thermocouple sensors are calibrated to a known standard. Each thermocouple element output is to a temperature-indicating switch. Testing of each thermocouple instrument loop may be accomplished in situ through the temperature-indicating switch via the test jack connection. A temperature-indicating switch contains a digital display of the process measurement and will display the trip setpoint when the setpoint pushbutton is depressed. As soon as the pushbutton is released, the input signal value returns to the display. An alarm light-emitting diode light is illuminated when a thermocouple has burned out or the process temperature measurement exceeds the process setpoint.

The testability of the resistance temperature detectors (RTDs) and trip units associated with the ATTS portion of the LDS is discussed in paragraph 7.8.3.9.

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

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

RWC differential flow leak detection is tested by inputting a signal to simulate a high differential flow. Alarm and indicator lights monitor the status of the trip circuit.

B. Power Supply

Inboard and outboard isolation valves in the same line are on separate power sources.

7.6.9.3 Analysis

The part of the LDS instrumentation that is related to the system isolation circuitry is designed to meet the requirements for ESF systems.

A differential temperature-sensing system is installed in each room containing equipment which is part of the nuclear system process barrier. This includes the RCIC, HPCI, and RWC systems. Temperature sensors monitor supply and exhaust air differential temperatures in selected areas outside the primary containment. A differential temperature switch between each set of sensors initiates an alarm in the MCR when the temperature difference reaches a point which indicates a leakage within the monitored room. A separate temperature-sensing system, consisting of RTDs and trip units, provides an independent isolation signal to each isolation valve. The system of temperature sensors and switches, which provide the alarm function, is not part of the ESF systems. This arrangement satisfies the single-failure criterion. The RTDs and the trip units are part of the ATTS, which is discussed in section 7.8.

The only time delays associated with any of the LDSs based upon temperature measurement (small breaks) are those for the HPCI steam line (15 min) and the RCIC steam line (30 min). MCR annunciation provides notification of time delay initiation and possible system isolation.

Each detection system is associated only with the isolation valves of the primary system which it is monitoring; thus, complete electrical and mechanical independence exists.

A consideration of the radiological consequences associated with the time delay in isolating breaks is relevant only to the HPCI and RCIC systems as indicated above. Calculations for these systems based on the time delays mentioned and assuming flow from the break to be 300% of rated flow for the system were made. Above this flow, no time delay would exist because of isolation from the flow sensors (instantaneous).

7.6.10 RECIRCULATION PUMP TRIP (HNP-1 AND HNP-2)

7.6.10.1 System Identification

The recirculation pump trip (RPT) system includes the sensors, logic circuitry, load drivers, switches, and circuit breakers that cause main power to be disconnected from both recirculation pump upon closure signals from the turbine stop valves or turbine control valve in the event of a turbine trip or generator load rejection.

The recirculation trip system is designed to aid the RPS in protecting the integrity of the fuel barrier. Turbine stop valve closure or turbine control valve fast closure will initiate a scram and concurrent recirculation trip in order to keep the core within the thermal-hydraulic safety limits during AOOs. The plant conditions which govern whether this trip is required to be in effect at a given time in the fuel cycle are described in each unit's Technical Specifications.

7.6.10.1.1 Safety Classification

The RPT system is a nonsafety-related system designed to Class 1E standards. The system functions to assist the RPS in maintaining the integrity of the fuel barrier during the AOOs identified in paragraph 7.6.10.1 and chapter 15.

7.6.10.1.2 Reference Design

The RPT system is not similar to any previous design although it does share certain redundant sensors and logic circuitry with the RPS.

7.6.10.2 Power Sources

The RPT system utilizes the RPS power supplies for the logic and the 125-V-dc for the breaker trip coils. The 125-V-dc is supplied by two separate divisions of station batteries which are Class 1E and also utilized by the RPS and the ECCS.

7.6.10.3 Equipment Design

7.6.10.3.1 Initiating Circuits

RPS inputs sense turbine stop valve closure (turbine trip) or turbine control valve fast closure (load rejection). These inputs utilize four-division RPS logic and are combined into the two-divisional, two-out-of-two systems utilized for RPT function. The devices utilized to sense turbine trip and full-load rejection are discussed in paragraph 7.2.2.2.

7.6.10.3.2 Logic

The basic logic arrangement is shown on figure 7.2-2. It is a two-divisional, two-out-of-two design. It receives signals from each of four RPS divisions. Initiation requires confirmation by sensors located in two or more RPS divisions. Failure to initiate requires failure in more than two RPS divisions. Inputs per division are combined in two-out-of-two configurations.

Each RPT division causes both recirculation pumps to trip off the main power supply.

7.6.10.3.3 Instrument Piping

Instrument piping is not required. Cables from sensors and power cables are routed such that no single event involving a single panel, cabinet, or raceway can disable the RPT function.

7.6.10.3.4 Actuated Devices

The actuator logic allows current to flow into the breaker trip coils when a trip signal is received. The breakers interrupt the main power supply when the coil is energized.

7.6.10.3.5 Separation

Sensors used to monitor for turbine trip and full-load rejection are incorporated in the RPS, where they are combined into a two-divisional system for input to the RPT system. All system wiring outside the cabinets are run in accordance with applicable separation requirements.

7.6.10.3.6 Testability

See paragraph 7.2.2.8.

7.6.10.4 Environmental Considerations

The electrical modules and sensors are located in the MCR and/or turbine building. The environmental conditions for these areas are shown in section 3.11.

7.6.10.5 Operational Considerations

7.6.10.5.1 Normal

Actuator logic is designated by channels A, B, C, D; actuation devices are designated (breaker trip coil) by divisions 1 and 2. During normal operation, the conditions of sensors and logic devices is shown on figure 7.2-7.

7.6.10.5.2 Operator Information

A. Indicators

   1. Trip initiate indicators, wired across the trip contacts, extinguish when actuator logic closes the contact to the breaker trip coil.

   2. Trip condition indicators are energized when the breaker is in an untripped condition as indicated by switch contacts mechanically tied to the breaker mechanism.

B. Annunciators

   1. Trip initiate annunciation is indicated by trip channel monitoring.

   2. Trip condition of the breakers is annunciated.

7.6.10.5.3 Setpoints

Initiate signals are provided by the RPS and are covered under paragraph 7.2.2.10.4.

7.6.10.6 Specific Regulatory Requirement Conformance

A. General Functional Requirement (IEEE 279 (1971), Paragraph 4.1)

Two instrument channels are connected to both division logics. In the division logics, the channels lose their identity since they are combined. The combination is two-out-of-two. When both instrument channels inputting a common divisional logic and monitoring the same variable exceed their setpoint, RPT will occur if an inhibit is not present.

B. Single-Failure Criterion (IEEE 279 (1971), Paragraph 4.2)

The design complies.

C. Quality of Components and Modules (IEEE 279 (1971), Paragraph 4.3)

The division logic consists of high-quality circuitry that has been proven to be highly reliable and is qualified per IEEE 323.

The actuators are devices selected to be operated substantially within their capabilities and are of high quality and reliability and qualified for their application per IEEE 323.

D. Equipment Qualification (IEEE 279, Paragraph 4.4)

At the component level, vendor certification is required that these parts will operate in accordance with the requirements of the purchase specification. General Electric (GE) will qualify the system, its components, modules, and subassemblies. In addition, insitu operational tests will be performed on the system during the preoperational test phase.

E. Channel Integrity (IEEE 279 (1971), Paragraph 4.5)

The logic system complies with this requirement.

F. Channel Independence (IEEE 279, Paragraph 4.6)

The two-division arrangement meets this requirement.

G. Control and Protection System Interaction (IEEE 279, Paragraph 4.7)

The two-division logics are totally separate from any nonprotection system. Due to the design of this output and separation of the cabling, there is no interaction with control systems of the plant. The actuator logic has no interaction with any other plant system, and the breaker trips are physically separate and electrically isolated from the other portions of the recirculation pump power supply. Consequently, this design requirement is met by this equipment. Any system interlocks to control

systems will only be isolated such that no failure or combination of failures will have any effect on RPT.

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

This design requirement is met by the instrument channels selected for inputs.

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

This design requirement is not literally applicable but by interpretation can be applied and is fully complied with by the input tests, logic tests, and output tests for which provisions are made. The system utilizes RPS sensors addressed in paragraph 7.2.2.8.

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

See subsection 7.2.2.8.

K. Channel Bypass or Removal from Operation (IEEE 279, Paragraph 4.11)

This design requirement is not applicable.

L. Operating Bypasses (IEEE 279, Paragraph 4.12)

This design requirement is not applicable.

M. Indication of Bypasses (IEEE 279, Paragraph 4.13)

This design requirement is complied with by indication of test bypasses and system inop switch.

N. Access to Means for Bypassing (IEEE 279, Paragraph 4.14)

This design requirement is complied with by operator control of test program.

O. Multiple Setpoints (IEEE 279, Paragraph 4.15)

This design requirement is not applicable.

P. Completion of Protective Action Once It Is Initiated (IEEE 279, Paragraph 4.16)

Once the RPT relays are tripped, they in turn trip the trip coils of the recirculation pump breakers.

Q. Manual Actuation (IEEE 279, Paragraph 4.17)

Manual activation is provided in the recirculation system.

R. Access to Setpoint Adjustments, Calibration, and Test Points (IEEE 279, Paragraph 4.18)

This design requirement is met. See paragraph 7.2.2.8.

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

MCR annunciators are provided to identify the tripped portions of RPT in addition to the previously described instrument channel annunciators associated with the RPS:

- Division 1 logic tripped.

- Division 2 logic tripped.

These same functions are connected to the process computer to provide a logged record of the system status.

T. Information Readout (IEEE 279, Paragraph 4.20)

The information presented to the MCR operator satisfies this design requirement.

U. Systems Repair (IEEE 279, Paragraph 4.21)

The design of this portion of the RPS complies with this design requirement.

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

See paragraph 7.2.2.6.

W. IEEE 308, Criteria for Class 1E Electric Systems

This does not apply to the logic system, which is fail safe. Its power supplies are thus unnecessary for RPT. A Class 1E system is required to energize the breaker trip coils.

X. IEEE 323, Standard General Guide for Qualifying Class 1 Electric Equipment

See paragraph 7.1.2.5.

Y. IEEE 338, Periodic Testing

See paragraph 7.2.3.3.

Z. IEEE 344, Seismic Requirements

All Class 1E equipment meets the requirements of section 3.10.

AA. IEEE 379, Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems

These requirements are satisfied by consideration of the different types of failure and carefully designing all violations of the single-failure criterion out of the system. An exception is imposed during periodic logic testing.

BB. Regulatory Guide 1.22

The system is designed so that it may be tested during plant operation from sensor device to final actuator logic. Circuit breaker is tested per Technical Specifications.

CC. Regulatory Guide 1.47, Positions C.1., C.2, and C.3

Annunciation is provided to indicate a part of a system is not operable. The system has annunciators lighting and sounding whenever one or more instrument channels are manually bypassed. Bypassing is not allowed in the trip logic or actuator logic. Indicator lights are provided to further identify the bypass.

All bypass and inoperability indicators both at the division level and the component level are grouped for operational convenience. As a result of design, preoperational testing, and startup testing, no erroneous bypass indication is anticipated.

These indication provisions serve to supplement administrative controls and aid the operator in assessing the availability of component and system level protective actions. This indication does not perform functions that are essential to the health and safety of the public.

All circuits are electrically independent of the plant safety systems to prevent the possibility of adverse effects. The annunciator initiation signals are provided through isolation devices and can in no way prevent protective actions. Each indicator is provided with dual lamps. Testing is included on a periodic basis when equipment associated with the indication is tested.

DD. Regulatory Guide 1.53

Compliance with Regulatory Guide 1.53 is by specifying, designing, and constructing the RPS to meet the single-failure criterion (section 4.2 of IEEE 279 (1971), "Criteria for Protection Systems for Nuclear Power Generating Station Protection System," and IEEE 379 (1972), "IEEE Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems.") Redundant sensors are used and the logic is arranged to ensure that a failure in a sensing element or the division logic or an actuator will not prevent RPT. Separate channels are employed so that a fault affecting one channel will not prevent the other channel from operating properly. Specifications are provided to define channel separation for wiring not included with GE supplied equipment.

EE. 10 CFR 50, Appendix A - General Design Criteria

- GDC 13 - Each system input is monitored and annunciated.
- GDC 19 - Controls and instrumentation are provided in the control room.
- GDC 20 - The system constantly monitors the appropriate plant variables and automatically initiates an RPT when the variables exceed setpoints.
- GDC 21 - The system is designed with four independent and separate output divisions. No single failure or operator action can prevent RPT. The instrument and logic can be tested during plant operation to assure its availability.
- GDC 22 - The redundant portions of the system are separated such that no single failure or credible natural disaster can prevent a trip.
- GDC 23 - Where the system is not fail safe, redundant Class 1E sources are utilized. Loss of an air supply will not prevent a scram. Postulated adverse environments will not prevent a scram.
- GDC 24 - The system has no control function. Signals for control room annunciation are isolated.
- GDC 29 - The system is highly reliable so that it will trip in the event of the anticipated operational occurrences.

FF. 10 CFR 50.62, Anticipated Transient Without Scram (ATWS) Requirements

Circuitry is provided to trip the reactor coolant recirculating pumps under conditions indicative of an ATWS. This circuitry is designed to perform its function in a reliable manner.

7.6.10.7 ATWS-RPT

A simultaneous trip of the recirculation pumps will occur upon either the receipt of a high RPV steam dome pressure signal or an indication of ATWS-RPT RPV water level as required by 10 CFR 50.62. The high RPV steam dome pressure setpoint is set higher, and the ATWS-RPT RPV water level setpoint is set lower than the normal scram setpoints such that a normal scram would have already been initiated at the time the alternate rod insertion or ATWS-RPT setpoint is reached. The ATWS-RPT system is not safety related.

7.6.11 POST-ACCIDENT SAMPLING SYSTEM (PASS)

7.6.11.1 Design Bases

The PASS is designed to provide grab samples of the reactor coolant and drywell atmosphere during normal or accident conditions.

7.6.11.2 System Description

The PASS is designed to take samples from both the HNP-1 and HNP-2 reactors and drywell atmospheres. Appropriate valving is provided such that the reactor coolant and containment atmosphere samples can be obtained from either unit at one location, the post-accident sampling room (PASR).

The reactor water sample line is routed from a jet pump flow-sensing line, downstream of the excess flow check valve, to the PASR and returns to the torus. Before a grab sample is taken, the sample lines are flushed to assure representative sampling. During normal operation, the reactor water is returned to the clean radwaste drains for processing, before being returned to the condensate storage tank. During accident conditions, the liquid samples are returned to the torus.

The containment air sample line is tied into the line leading to the fission products monitor panels (FPMPs), downstream of the primary containment isolation valves. The line is routed to the PASR and from the PASR to the FPMP return line, upstream of the primary containment isolation valves.

System operation is controlled by a computer which has the capability to be manually overridden. Drawing no. H-26384 shows a schematic representation of the sample lines from both HNP-1 and HNP-2 that lead to the PASR.

7.6.11.3 Analysis

The PASS is controlled from the chemistry area in the control building. Equipment in the PASR provides grab sample capability. The grab sample system is designed so that operator doses, assuming source terms consistent with the Regulatory Guide 1.3 requirements, will be as low as reasonably achievable.

7.6.11.4 Safety Evaluation

The PASS is a nonsafety-related and Seismic Category Class II system. To maintain the integrity of the reactor pressure boundary, the sample line is equipped with two ASME Code, Section III, Class 2, fail-closed air-operated valves in series for isolation, which meet the 10 CFR 50.49 requirements. The system is powered by an essential ac bus; however, the

cable routing is classified as nonessential. Electric power for the containment isolation valves is provided from an essential ac bus which can receive standby power in case of an LOSP.

7.6.12 PLANT SERVICE WATER SYSTEM

The plant service water (PSW) system supports the operation of the ECCS.

7.6.12.1 Design Bases

The design bases are given in paragraph 9.2.1.1.

7.6.12.2 System Description

The PSW system is described in subsection 9.2.1. The following discussion provides additional information on PSW initiation and isolation functions.

7.6.12.2.1 Identification and Classification

The PSW provides cooling water to safety and nonsafety systems. The controls and instrumentation for the safety-related portion of the PSW are designed to Class 1E requirements. The isolation valves and system classification are shown on drawing nos. H-21033, H-26050, and H-26051.

7.6.12.2.2 Initiation Signals

The PSW system is normally under manual control from the MCR with three pumps in operation. Automatic starting of the standby pump is initiated by a low-pressure signal from pressure switch 2P41-N301A or B (drawing no. H-21033). Automatic isolation of the nonessential portions of the PSW system is initiated by the following:

- LOCA or LOSP signal.
- Turbine building high-water level (2N71-N322A-D and N323A-D).

7.6.12.2.3 Circuit Description

The logic and equipment actuated by the initiation signals are discussed in paragraph 9.2.1.4. Signal override for the automatic LOCA and LOSP signals, as discussed in paragraph 7.6.12.3, is provided for the PSW system turbine building isolation valves.

7.6.12.2.4 Redundancy, Diversity, and Separation

The PSW system instrumentation and controls are divided into redundant divisions which meet the separation criteria outlined in paragraph 8.3.1.4.1.

7.6.12.2.5 Testability

Test jacks, permanently wired to the existing normal control circuitry, are used to simulate LOSP, LOCA, or turbine building flooding initiation signals during testing of the isolation functions of the PSW system. The automatic starting (upon low-pressure signal) of the pump is tested by placing the control switch in the auto mode with no system pressure.

7.6.12.2.6 Supporting Systems

The instrumentation and controls receive power from essential buses.

7.6.12.2.7 Operational Considerations

Valve and pump operating startup is provided in the MCR by indicating lights. Setpoints are provided in table 7.6-13.

7.6.12.3 <u>Analysis</u>

A failure analysis is provided in table 9.2-3, and a safety evaluation of the system is provided in paragraph 9.2.1.4.

The PSW system meets the requirements of IEEE Standard 279-1971, except as described below:

A. Paragraph 4.13 - Indication of Bypasses

   For the PSW system, keylock switches are provided in the MCR to override the automatic LOCA and LOSP signals which cause turbine building isolation valves to close. This override is a permissive to allow reopening of these valves following an automatic LOCA and LOSP signal but does not override the condenser room flooding signal. Indication of the override is displayed by the keylock switch position.

B. Paragraph 4.17 - Manual Initiation

   For the PSW system, means for system level manual initiation are not provided, since both divisions of the system are continuously running during plant operation.

REFERENCES

1. "Incore Neutron Monitoring System for General Electric Boiling Water Reactor," GE Topical Report APED-5706, November 1968 (Revised April 1969).

2. (Deleted)

3. "Average Power Range Monitor, Rod Block Monitor, and Technical Specification Improvements (ARTS) Program for Edwin I. Hatch Nuclear Plant, Units 1 and 2," NEDC-30474-P, December 1983.

4. "Banked Position Withdrawal Sequence," NEDO-21231, January 1977.

5. "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," NEDC-32410P-A, Volumes 1 and 2, October 1995, Supplement One, November 1997.

TABLE 7.6-1 (SHEET 1 OF 2)

REFUELING INTERLOCK EFFECTIVENESS

Situation	Refueling Platform Position	Refueling TMH	Platform FMH	Hoists FG	Control Rods	Mode Switch	Attempt	Result
1	Not near core	UL	UL	UL	All rods in	Refuel	Move refueling platform over core	No restrictions
2	Not near core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
3	Not near core	UL	UL	UL	One rod withdrawn	Refuel	Move refueling platform over core	No restrictions
4	Not near core	Any hoist loaded or FG not fully up			One or more rods withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
5	Not near core	UL	UL	UL	More than one rod withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
6	Over core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
7	Over core	Any hoist loaded or FG not fully up			All rods in	Refuel	Withdraw rods	Rod block
8	Not near core	UL	UL	UL	All rods in	Refuel	Withdraw rods	Rod block
9*								
10*								
11	Not near core	UL	UL	UL	All rods in	Startup	Move refueling platform over core	Platform stopped before over core

TABLE 7.6-1 (SHEET 2 OF 2)

Situation	Refueling Platform Position	Refueling TMH	Platform FMH	Hoists FG	Control Rods	Mode Switch	Attempt	Result
12*								
13*								
14	Not near core	UL	UL	UL	All rods in	Startup	Withdraw rods	Rod block
15	Not near core	UL	UL	UL	All rods in	Startup	Withdraw rods	No restrictions
16	Over core	UL	UL	UL	All rods in	Startup	Withdraw rods	Rod block
17	Any	Any condition			Any condition reactor pressure < 825 psig	Startup	Turn mode switch	Scram

LEGEND

TMH - Trolley-mounted hoist
FMH - Frame-mounted hoist
FG - Fuel grapple
UL - Unloaded
L - Fuel loaded
*Situations 9, 10, 12, and 13 do not exist because the reactor vessel service platform has been removed.

TABLE 7.6-2

NMS INSTRUMENT DATA

	SRM	IRM	LPRM	APRM	TIP	RBM
Design Classes Quality/Seismic	III/II	I/I	I/I	I/I	III/II	III/II
Power supply	± 24 V-dc buses	± 24 V-dc buses	120 V-ac RPS buses	120 V-ac RPS buses	120 V-ac local power bus buses	120 V-ac RPS buses
No. of channels	4	8	124	4	4	2
Alarm setpoint(s)			Process computer generated	Varies with core flow	NA	Varies with core power
Control setpoint(s)			NA	Varies with core flow	NA	Input from APRM
Control logic	1/4 for rod blocks	1/8 trips RPS; 1 channel isolatable	Loss of power trips RPS	Table 7.6-6	NA	1/2
Instrument range	1×100^3 to 1×10^9 nv	10^8 -1.5 x 10^5 nv to 2.8×10^{14} nv		0-125% full power	2.8×10^{12} to 2.8×10^{14} nv	0-125% power
Instrument accuracy	± 10% linear	± 15%	± 1% full scale	± 1% full scale	Position ± 1 in flux ± 1.0% full scale	± 1.5%
Response time	Variable response time	≤ 120 on ranges 7-10	Variable response time	~ 20 ms	NA	5 ms
Testing recalibration schedule			TIP	TIP	Intercalibration with other TIPs	

TABLE 7.6-3

SRM SYSTEM TRIPS

Trip Function	Nominal Setpoint	Trip Action[a]
SRM upscale (high)	(c)	Rod block, amber light display, annunciator
SRM instrument inoperative	(b)	Rod block, amber light display, annunciator
Detector retraction permissive (SRM downscale)	(c)	Bypass detector full-in limit switch when above preset limit, annunciator, green light display, rod block when below preset limit with IRM range switches on first two ranges
SRM period	50 s	Annunciator, amber light display
SRM downscale	3 Hz	White light display, annunciator, rod block
SRM bypassed		White light display

a. Also refer to figure 7.6-1.
b. Operate-calibrate switch not in operate position, module interlocks open, detector polarizing voltage < 300 V.
c. Allowable values are specified in HNP-2 Technical Requirements Manual. See HNP-2 Instrument Setpoint Index for actual setpoints.

TABLE 7.6-4

IRM SYSTEM TRIPS

Trip Function	Nominal Setpoint	Trip Action[b]
IRM upscale (high-high)	(a)	Scram, annunciator, red light display
IRM instrument inoperative	(c)	Scram, annunciator, red light display
IRM upscale (high)	(d)	Rod block, annunciator, amber light display
IRM downscale	(d)	Rod block (exception on most sensitive scale), annunciator white light display
IRM bypassed		White light display

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Also refer to figure 7.6-1.
c. Operate-calibrate switch not in operate position, module interlocks open, detector polarizing voltage < 80 V.
d. Allowable values are specified in HNP-2 Technical Requirements Manual. See HNP-2 Instrument Setpoint Index for actual setpoints.

TABLE 7.6-5

LPRM SYSTEM TRIPS

Trip Function	Trip Range	Trip Setpoint	Trip Action
LPRM downscale	0% to 125%	(a)	Operator display assembly and annunciator
LPRM upscale	0% to 125%	(a)	Operator display assembly and annunciator
LPRM bypass	Manual switch		Operator display assembly and APRM compensation

a. See the Instrument Setpoint Index for the actual trip setpoints.

TABLE 7.6-7

APRM SYSTEM TRIPS

Trip Function	Trip Point Range	Nominal Setpoint	Action
APRM downscale	0% to 125%	(b)	Rod block, annunciator, operator display assembly
APRM upscale (high), run mode	Varies with flow, intercept and slope adjustable	(b)	Rod block, annunciator, operator display assembly
APRM upscale thermal power monitor (high-high), run mode	Varies with flow, intercept and slope adjustable	(a)	Scram, annunciator, operator display assembly
APRM inoperative		Not in operate mode or < 17 LPRM inputs per APRM	Scram, rod block, annunciator operator display assembly
APRM bypass	Manual switch	---	Operator display assembly
APRM upscale (high) startup mode and during shutdown margin testing in mode 5	7% to 27%	(b)	Rod block, annunciator, operator display assembly
APRM upscale (high-high) startup mode and during shutdown margin testing in mode 5	10% to 30%	(a)	Scram, annunciator, operator display assembly
APRM neutron flux (high), run mode	0% to 125%	(a)	Scram, annunciator, operator display assembly

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. See HNP-2 Instrument Setpoint Index for the actual setpoints.

TABLE 7.6-8

RBM SYSTEM TRIPS

Trip Function	Setpoint	Trip Action
RBM downscale	(a)	Rod block, annunciator, Operator display assembly
RBM inoperative	(b)	Rod block, annunciator, Operator display assembly
RBM upscale	(a)	Rod block, annunciator, Operator display assembly
RBM bypassed	Manual switch	Operator display assembly

a. Allowable values are listed in HNP-2 Technical Specifications. See HNP-2 Instrument Setpoint Index for actual setpoints.
b. Not in operate or too few inputs.

TABLE 7.6-9 (SHEET 1 OF 2)

PRIMARY CONTAINMENT ATMOSPHERE MONITORS - INSTRUMENT DATA

Variable	Instrument Range and Measurement Units	Range of Values in Normal Operation	Range of Values in Post-Accident Condition
Pressure			
Drywell			
(wide range)	0 to +250 psig	0.75 ± 0.1 psig	0.75 - 56 psig
(mid range)	-10/0/+90 psig	0.75 ± 0.1 psig	0.75 - 56 psig
(narrow range)	-5/0/+5 psig	0.75 ± 0.1 psig	
Torus	-10/0/+90 psig	0.75 ± 0.1 psig	0.75 - 56 psig
Temperature			
Drywell air	0 - 400°F	135°F normal 150°F maximum	290°F
Torus (water)[c,d]	0 - 400°F	≤ 100°F	95 - 200°F
Torus water average bulk temperature[c,d]	50 - 250°F	≤ 100°F	95 - 200°F
Torus water level			
(wide range)	0 - 300-in. WC	146 - 150-in. WC	-
(narrow range)	133 - 163-in. WC	146 - 150-in. WC	-
O_2 concentration			
Drywell	0 - 10 vol % 0 - 30 vol %	(b)	(a)
Torus	0 - 10 vol % 0 - 30 vol %	(b)	(a)
H_2 concentration			
Drywell	0 - 10 vol % 0 - 50 vol %	(b)	< 3.4 vol %

TABLE 7.6-9 (SHEET 2 OF 2)

Variable	Instrument Range and Measurement Units	Range of Values in Normal Operation	Range of Values in Post-Accident Condition
Torus	0 - 10 vol % 0 - 50 vol %	(b)	< 3.4 vol %
Fission products			
Particulate and iodine	10 - 10^6 cpm	≥ 1 x 10^{-9} μCi/cc	-
Noble gases	10 - 10^6 cpm	≥ 1 x 10^{-6} μCi/cc	≤ 1.5 x 10^{-5} μCi/cc
Post-LOCA gamma monitor	1 - 10^{-7} R/h	Negligible	

a. O_2 is not controlled following a LOCA.
b. H_2/O_2 analyzer does not operate during normal operation.
c. Reference HNP-2 FSAR paragraph 5.5.7.3.1 for discussion of suppression pool temperature monitoring system.
d. The suppression pool temperature limit for normal operation was increased to 100°F, but will normally be < 100°F.

TABLE 7.6-10

RWC SYSTEM - MCR ANNUNCIATION

2H11-P602

Cleanup system high conductivity

Cleanup discharge pressure (high/low)

Cleanup pump high temp trip

Cleanup system leak

Pump low flow

Cleanup filter-demineralizer failure

Filter inlet temperature (high)

TABLE 7.6-11

LEAK DETECTION SYSTEM INSTRUMENT DATA

	RPV Heat Seal Pressure	SRV Tailpipe Temperature	RHR Area Temperature	RHR Differential Temperature	MSL Tunnel Differential Temperature	MSL Area Temperature
Design Classes Quality/Seismic	III/II	III/II	III/II	III/II	III/II	III/II
Power supply	125 V-ac instrument bus	NA	125 V-ac instrument bus	125 V-ac instrument bus	125 V-ac instrument bus	125 V-ac instrument bus
No. of channels	1	11	2	2	1	16
Alarm setpoint(s)	600 psig	(a)	175°F	50°F	70°F	200°F
Instrument range	0-1500 psig	100 - 600°F	50 - 350°F	50 - 350°F	0 - 150°F	75 - 375°F
Instrument accuracy	± 30 psig	-	± 6	± 6°F	± 1°F	± 2°F

a. The annunciation setpoint for high SRV tailpipe temperature is controlled administratively by plant procedure to prevent the masking of valve degradation for the remaining valves when one or more valves have previously exceeded the setpoint and provide a method by which further degradation of an individual valve can be monitored.

TABLE 7.6-12

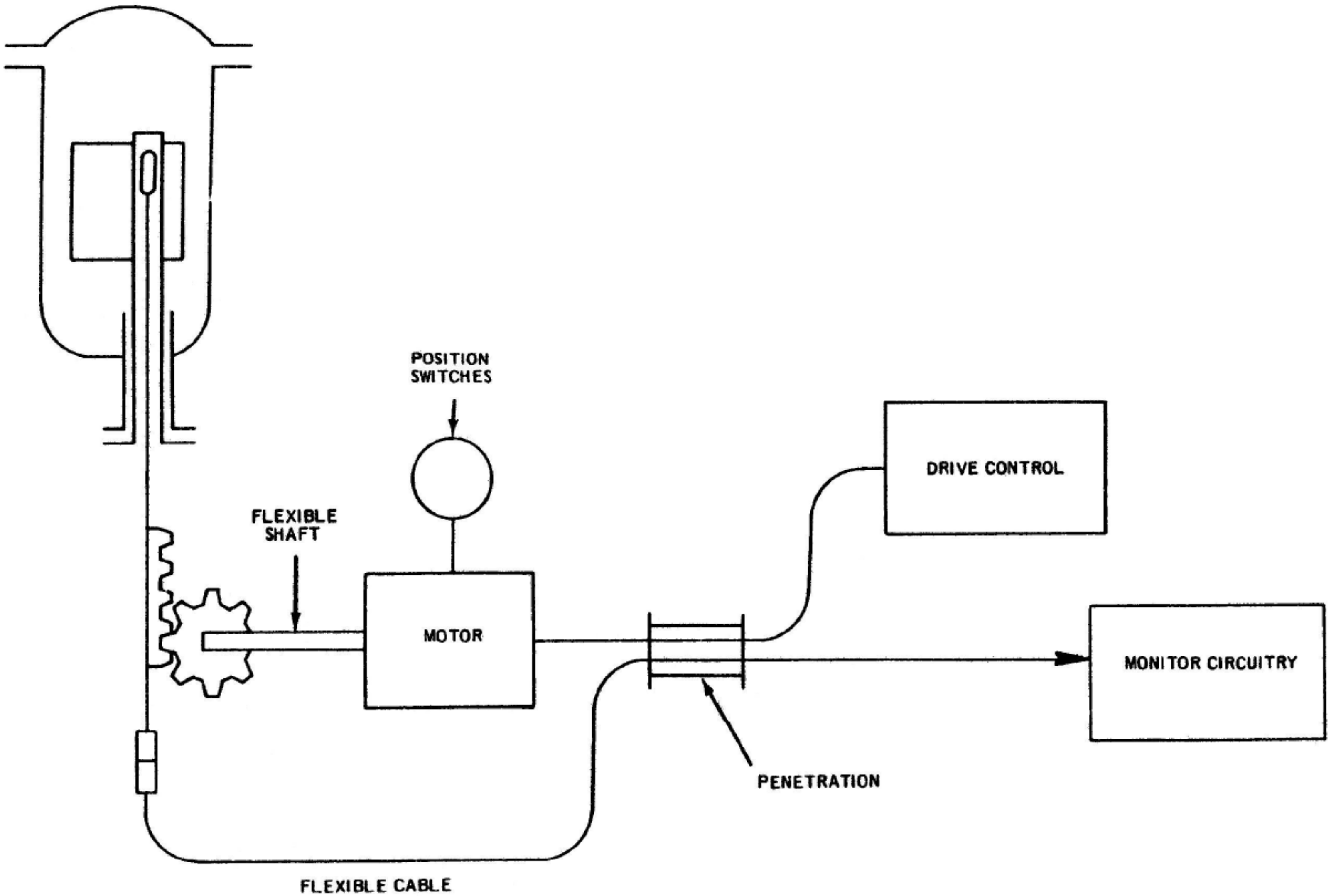
POST-ACCIDENT SAMPLING SYSTEM

DELETED.

TABLE 7.6-13

PSW INSTRUMENT TRIP SETTINGS

Instrument	Function	Setpoint
2P41-N301, A,B	Low-pressure start signal	95 psig (falling)



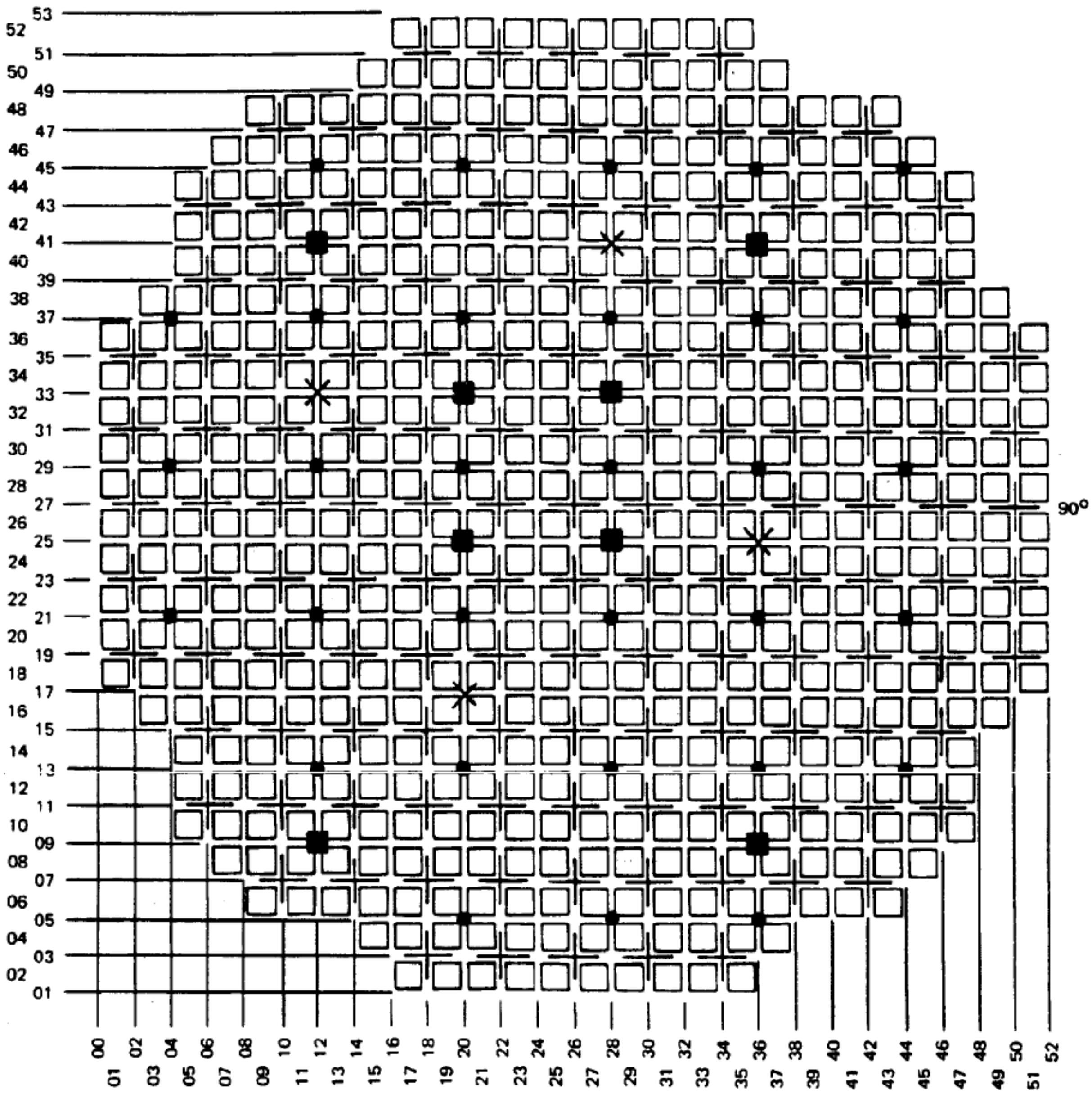
REV 19 7/01

DETECTOR DRIVE – SCHEMATIC

FIGURE 7.6-1

NEUTRON MONITOR SYSTEM DETECTOR CORE LOCATIONS

TOP VIEW
0°



●	LOCAL POWER RANGE MONITORING SYSTEM (LPRM)	31
X	SOURCE RANGE MONITORING SYSTEM (SRM)	4
■	INTERMEDIATE RANGE MONITORING SYSTEM (IRM)	8
	TOTAL PENETRATIONS FOR NUCLEAR INSTRUMENTS	43

ACAD 2070602

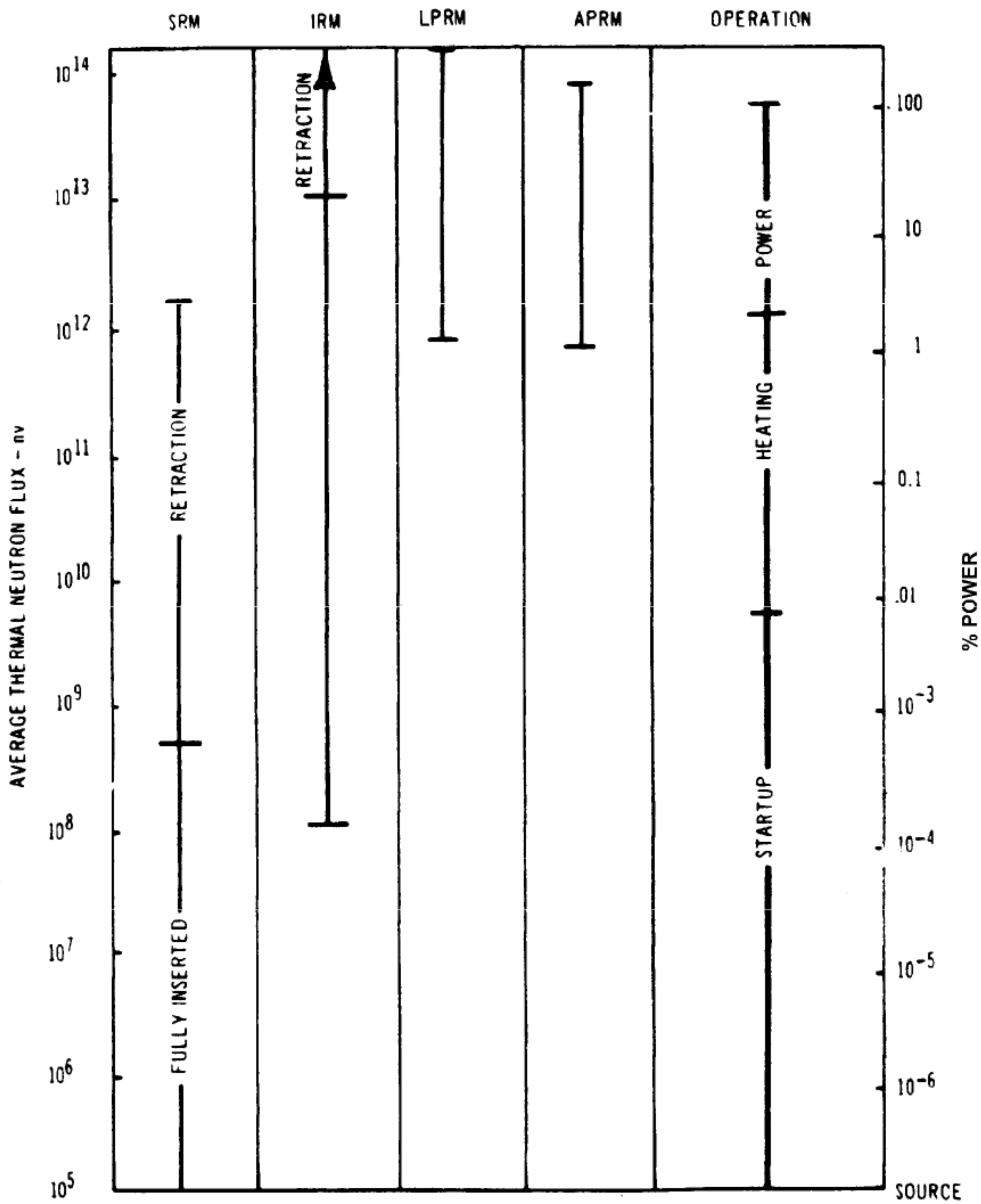
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NMS DETECTOR CORE LOCATIONS

FIGURE 7.6-2



ACAD 2070603

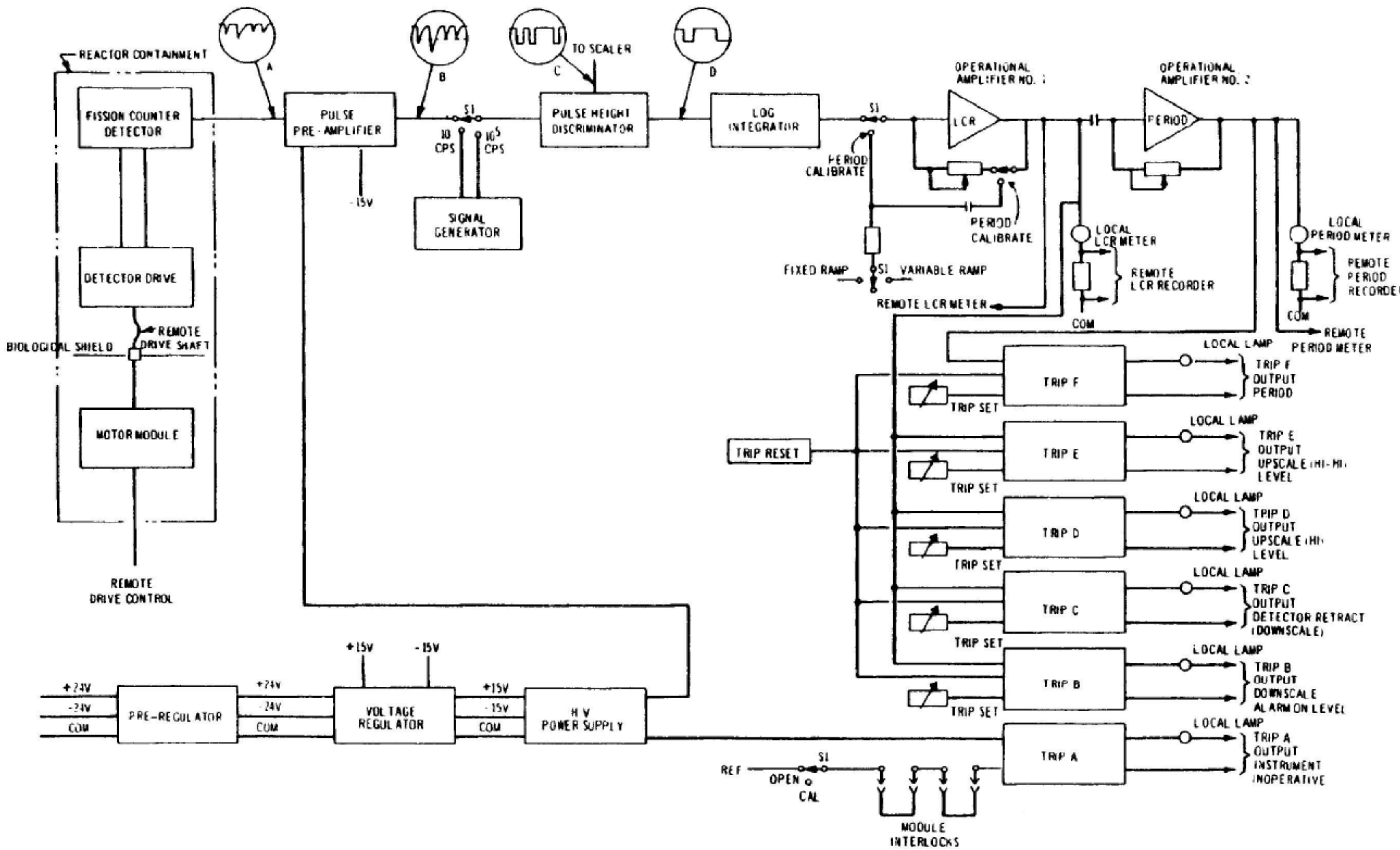
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

NMS INSTRUMENTATION RANGES

FIGURE 7.6-3



ACAD 2070604

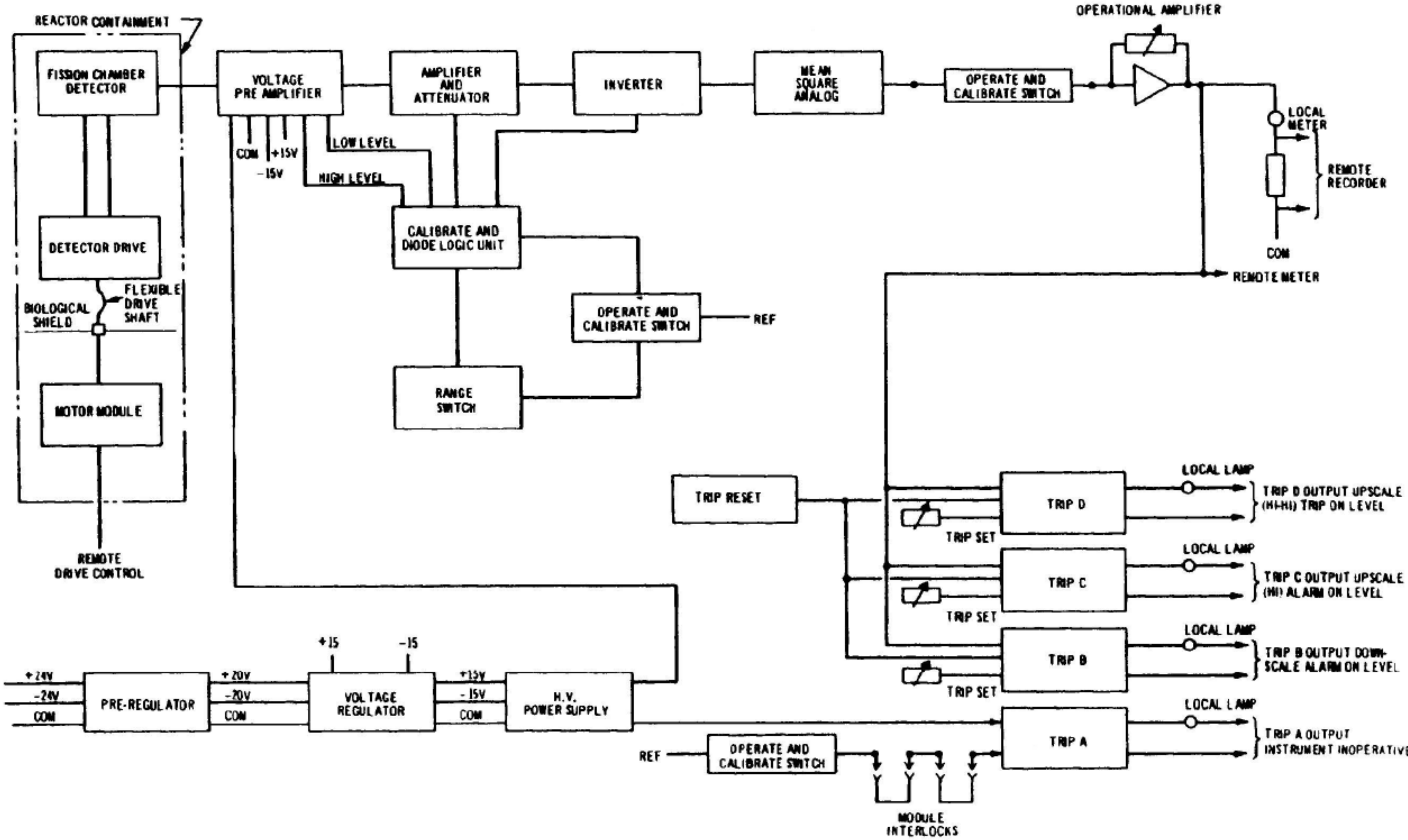
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SRM FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.6-4



ACAD 2070605

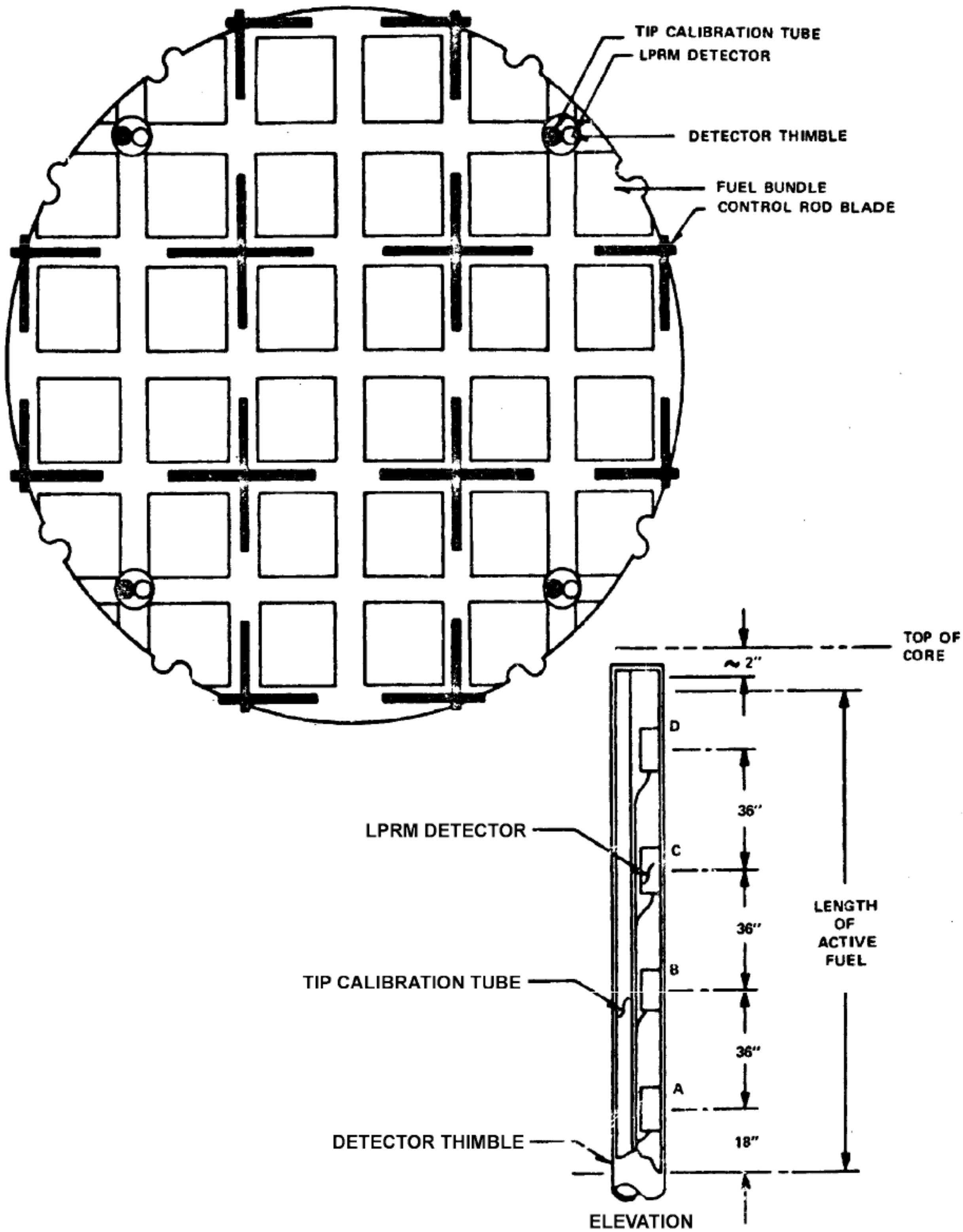
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

IRM FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.6-5



ACAD 2070606

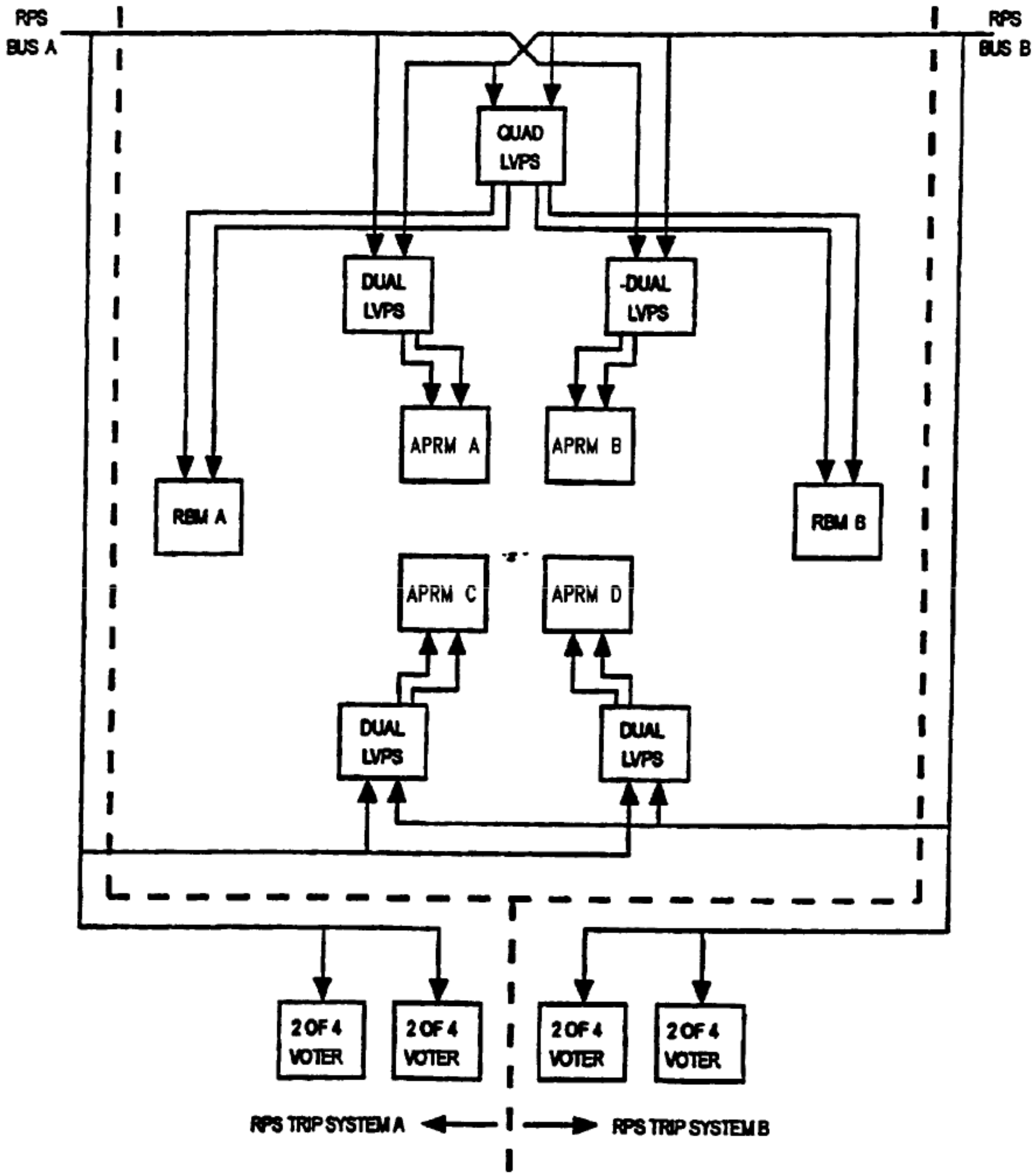
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

POWER RANGE MONITOR DETECTOR ASSEMBLY LOCATION

FIGURE 7.6-6



ACAD 20706071

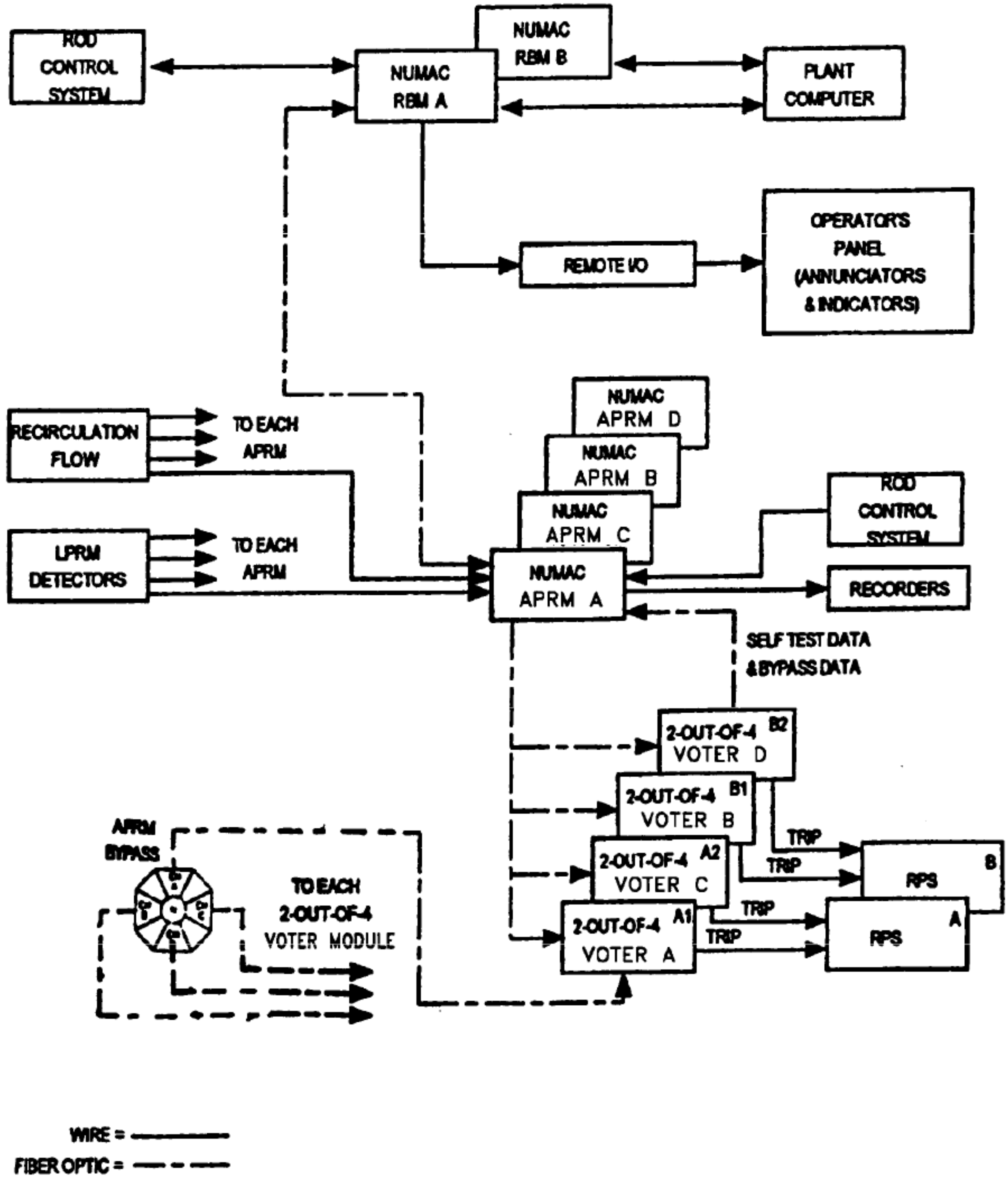
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

APRM/RBM POWER DISTRIBUTION

FIGURE 7.6-7 (SHEET 1 OF 5)



ACAD 20706072

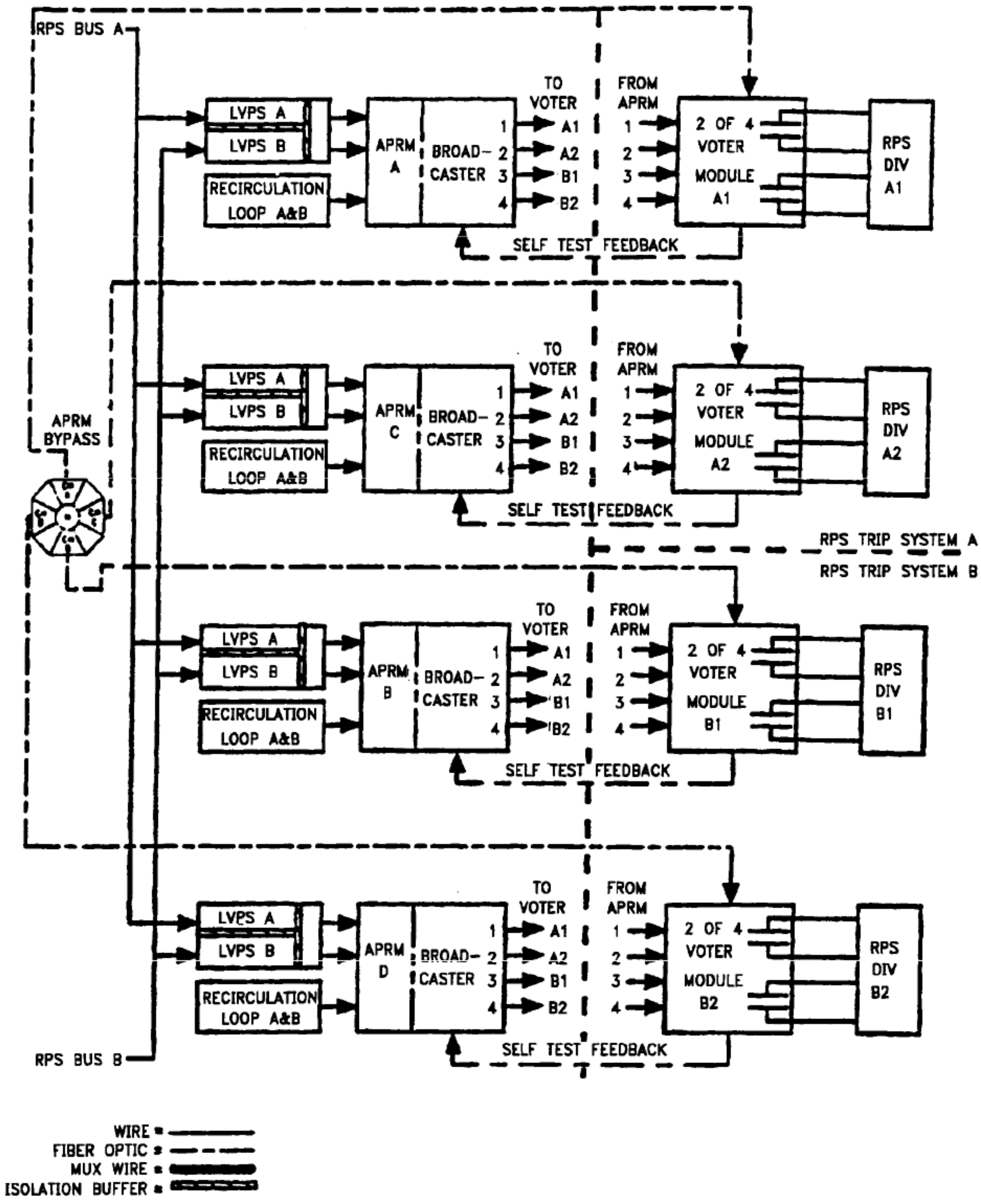
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

PRNM LOGIC INTERFACE BLOCK DIAGRAM

FIGURE 7.6-7 (SHEET 2 OF 5)



ACAD 20706073

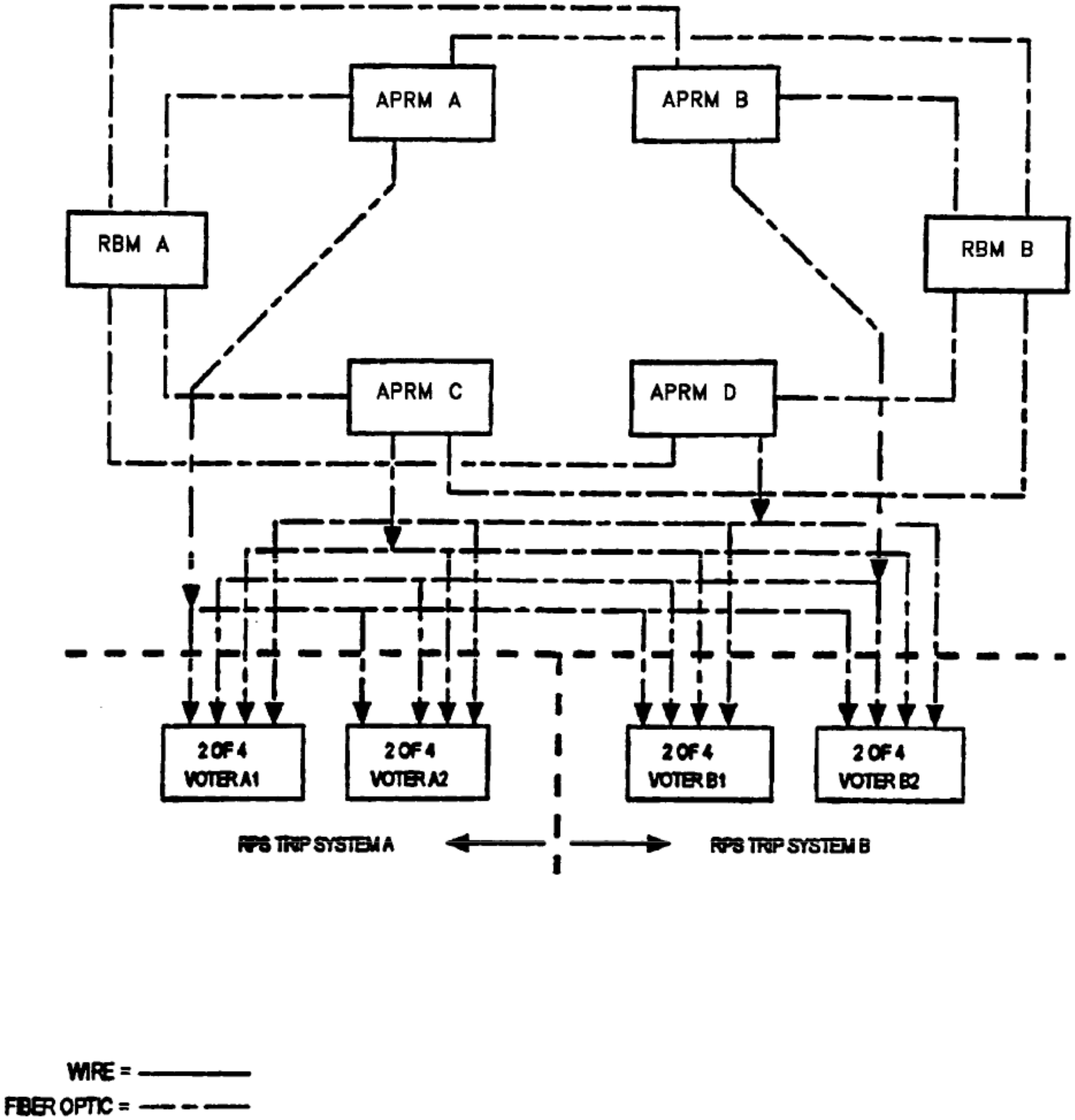
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

APRM/RPS INTERFACE BLOCK DIAGRAM

FIGURE 7.6-7 (SHEET 3 OF 5)



ACAD 20706074

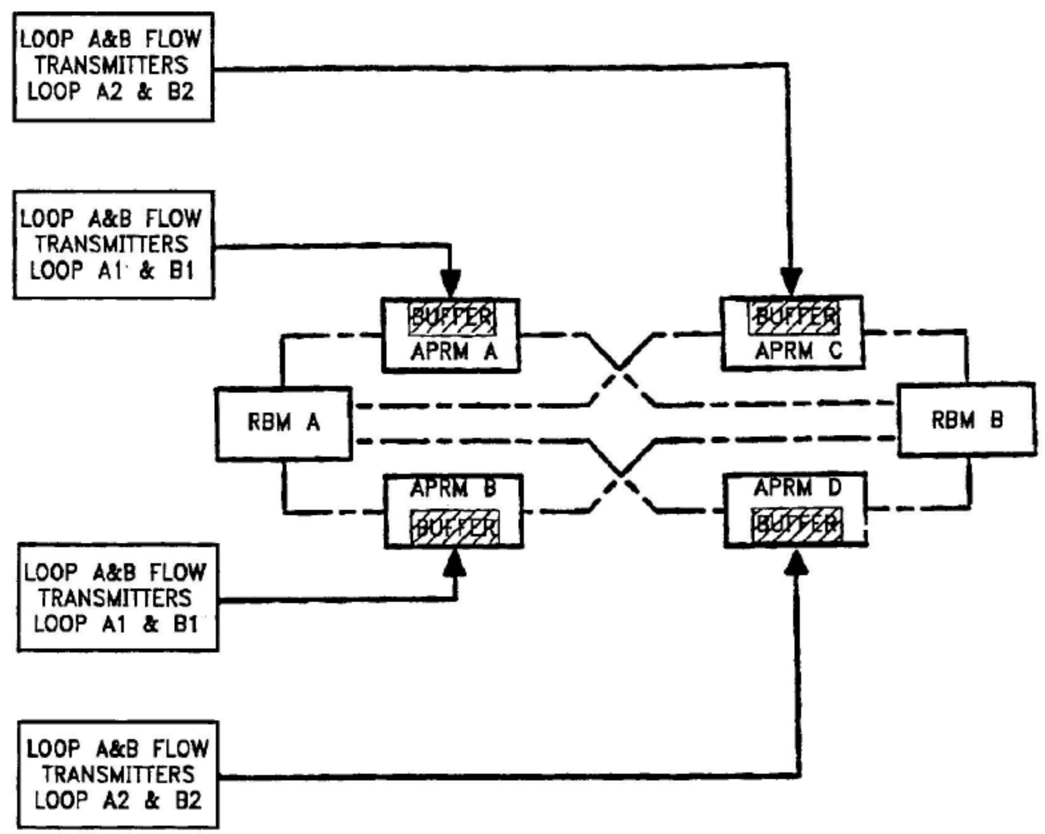
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

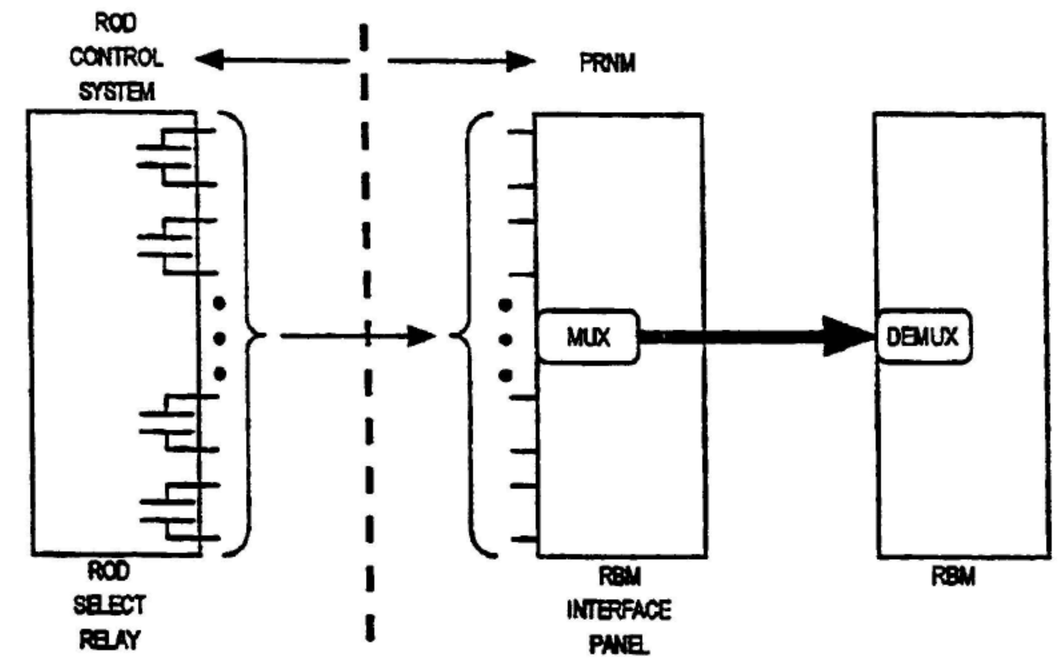
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

APRM/RBM CONFIGURATION BLOCK DIAGRAM

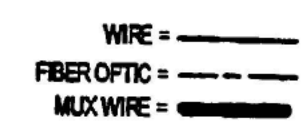
FIGURE 7.6-7 (SHEET 4 OF 5)



APRM/Flow Interface Block Diagram



RBM/Rod Control System Interface Block Diagram



ACAD 20706075

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

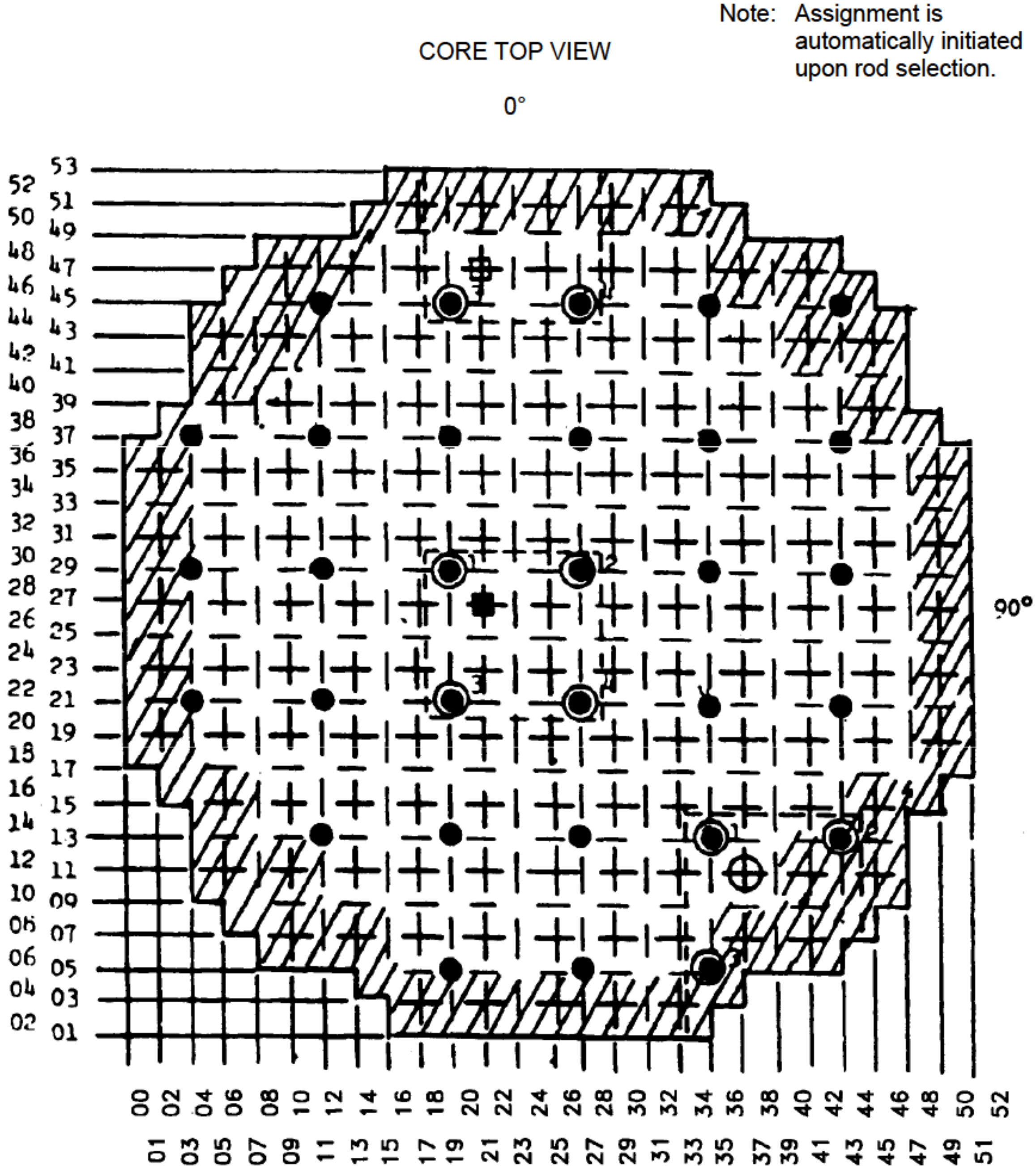
SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

FLOW REFERENCE AND
RBM INSTRUMENTATION

FIGURE 7.6-7 (SHEET 5 OF 5)

TYPICAL ASSIGNMENT OF LPRM INPUT TO RBM SYSTEM

Note: Assignment is automatically initiated upon rod selection.



///RBM Automatically bypassed (Reading Zeroed)

□ Typical Rod Yielding Two Power Range Detector Assemblies

○ Typical Rod Yielding Three Power Range Detector Assemblies

■ Typical Rod Yielding Four Power Range Detector Assemblies

ACAD 20706081

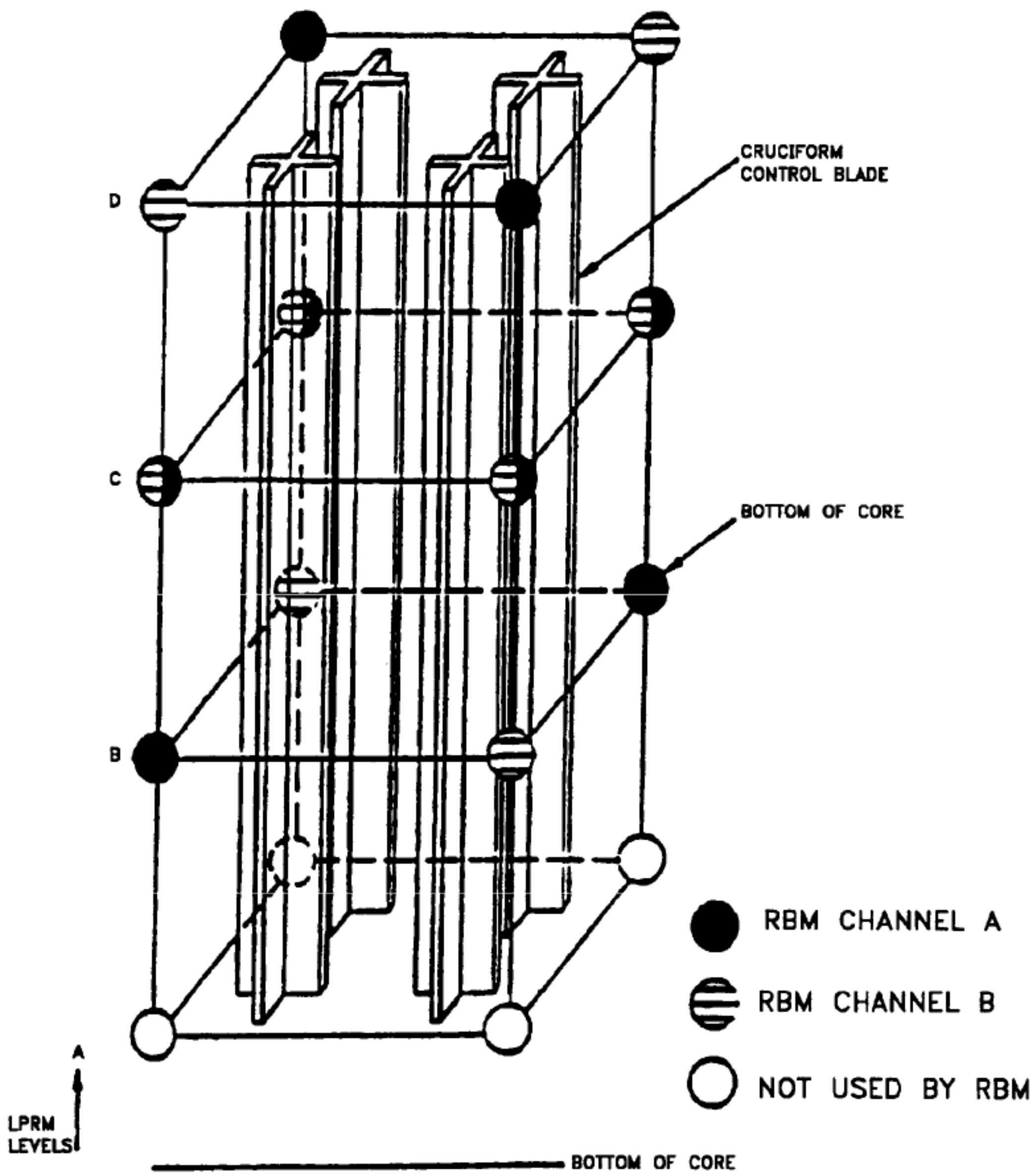
REV 19 7/01

SOUTHERN COMPANY Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LPRM TO RBM ASSIGNMENT SCHEME

FIGURE 7.6-8 (SHEET 1 OF 2)



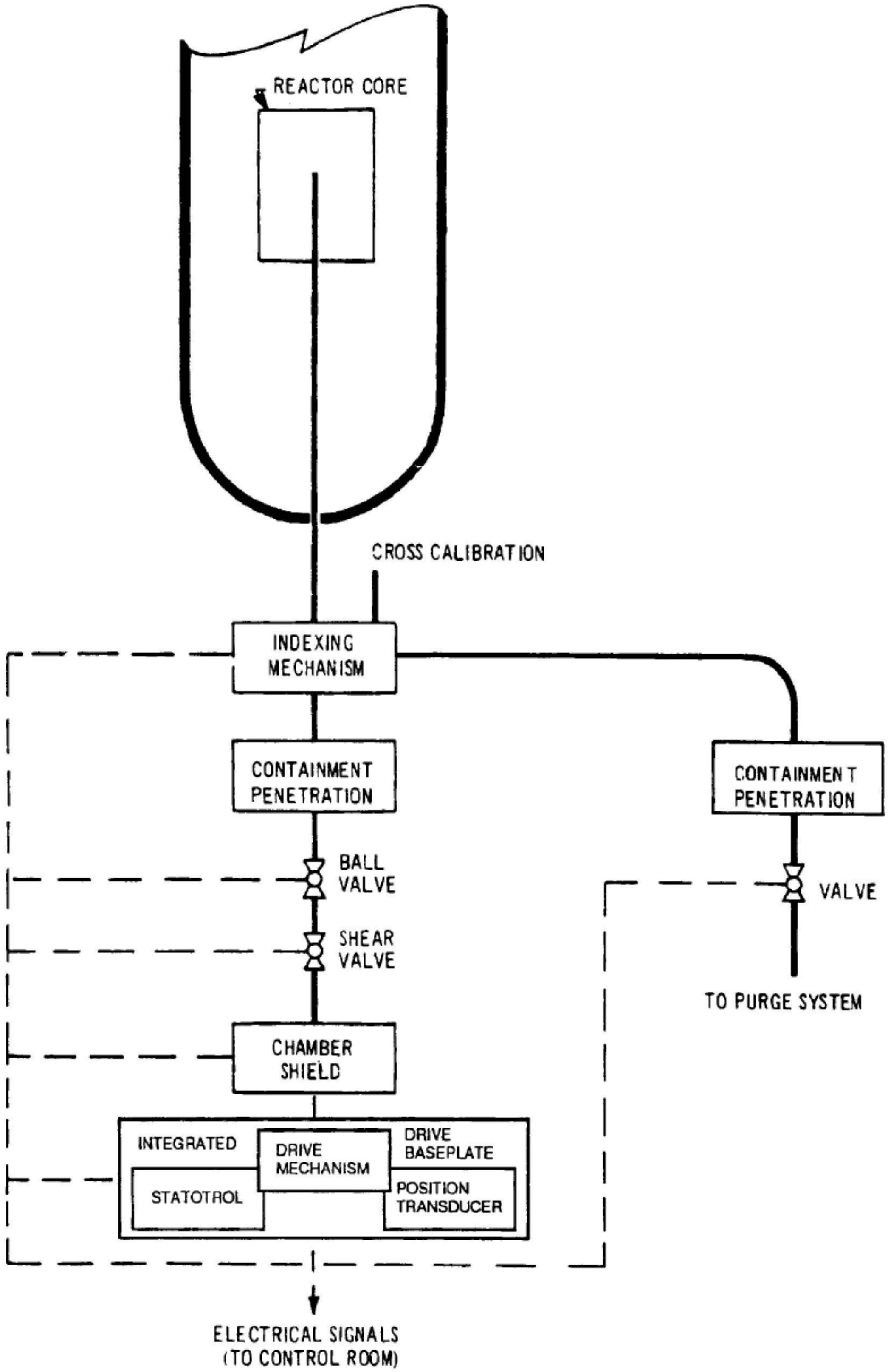
ACAD 20706082

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

LPRM TO RBM ASSIGNMENT SCHEME

FIGURE 7.6-8 (SHEET 2 OF 2)



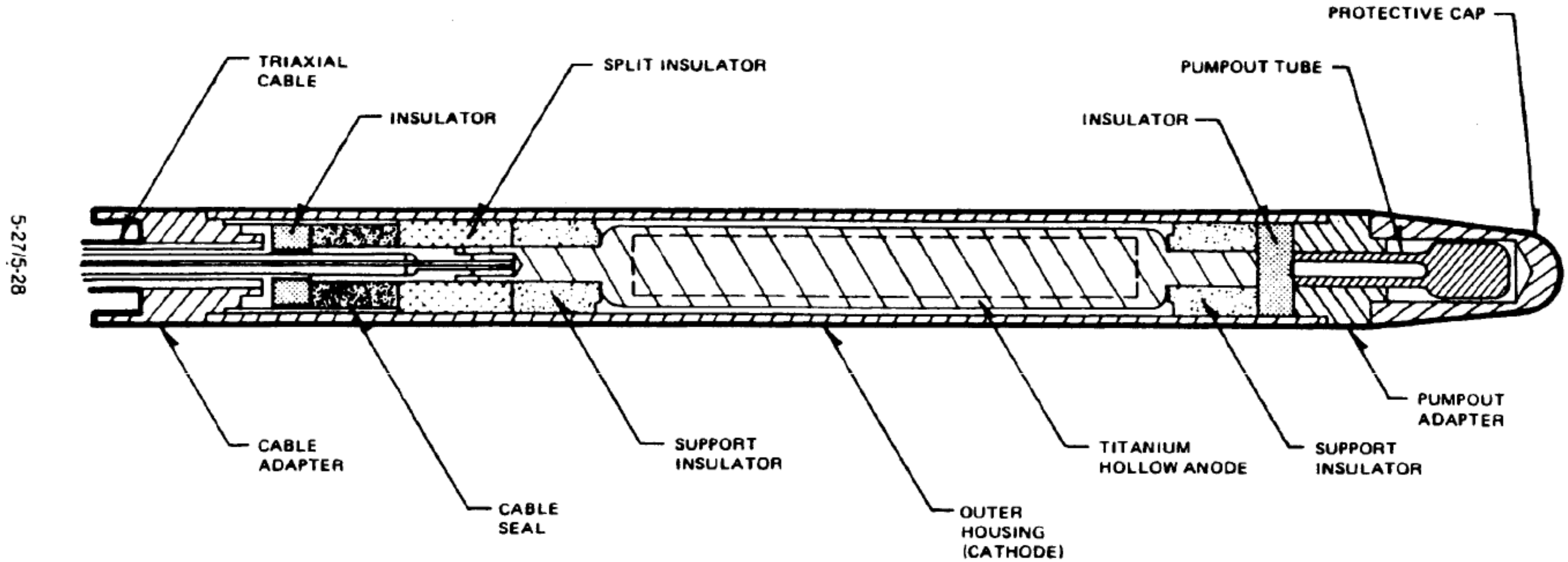
ACAD 2070609

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIP FUNCTIONAL BLOCK DIAGRAM

FIGURE 7.6-9



ACAD 2070610

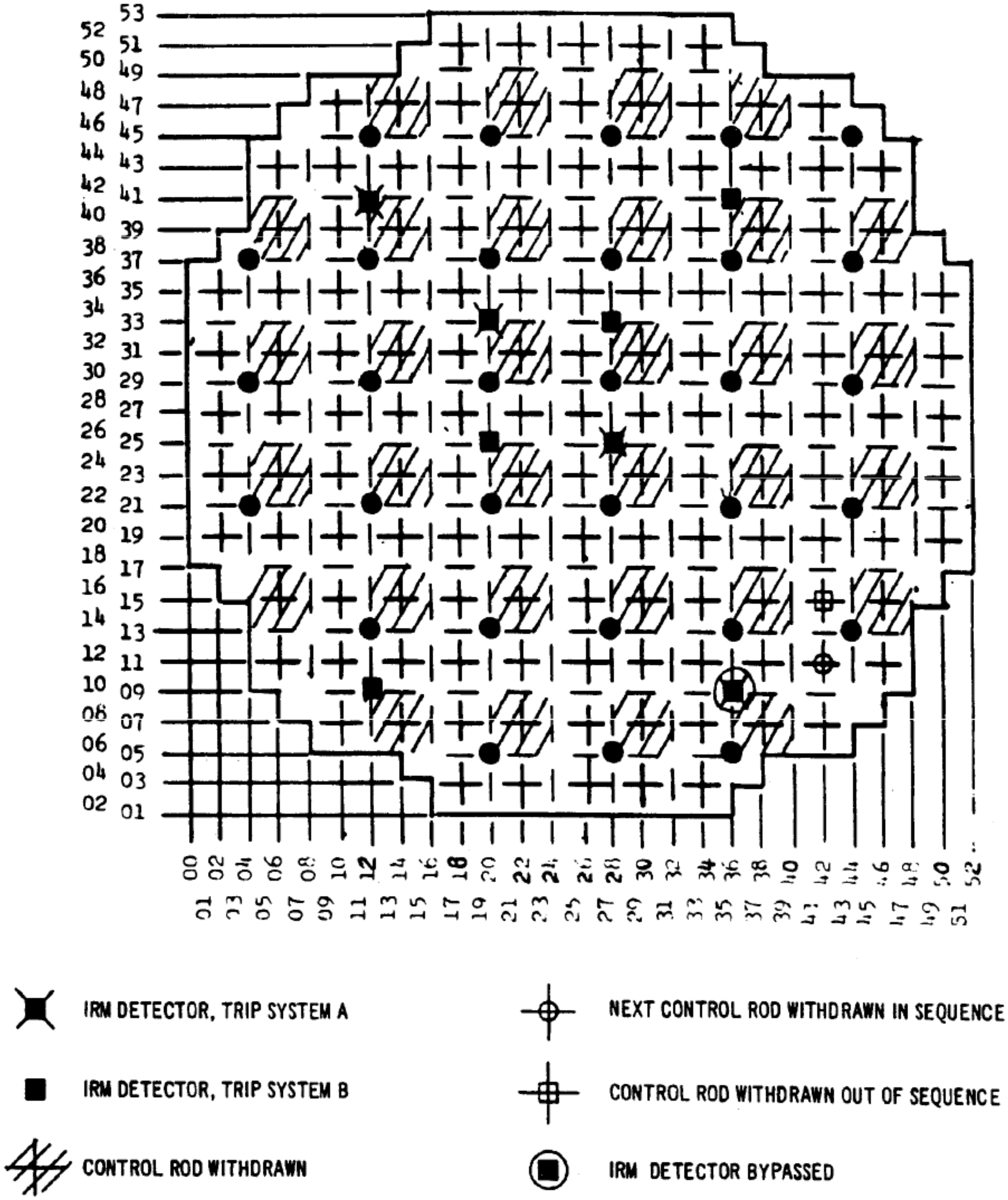
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TIP ASSEMBLY

FIGURE 7.6-10



ACAD 2070611

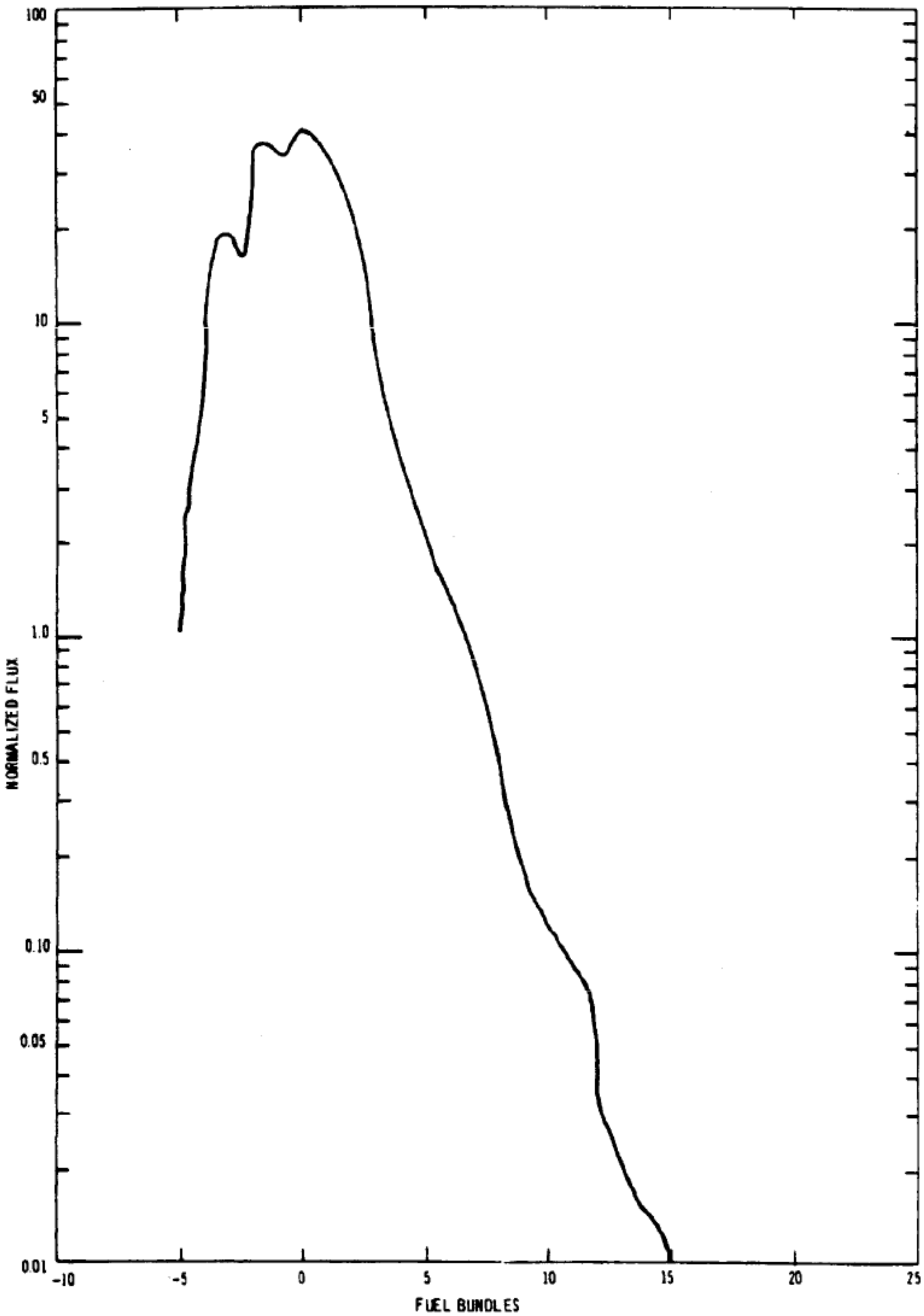
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTROL ROD WITHDRAWAL ERROR
CORE LOCATIONS

FIGURE 7.6-11



ACAD 2070612

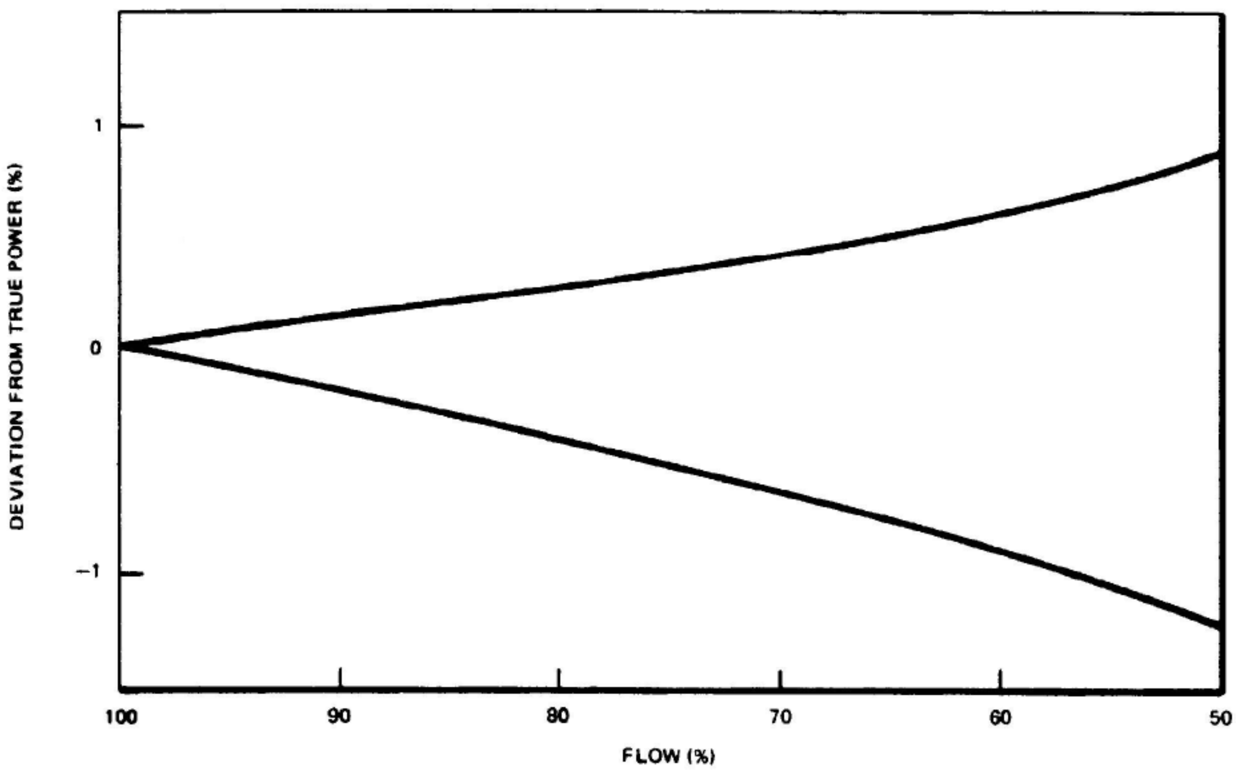
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

CONTROL ROD WITHDRAWAL ERROR
NORMALIZED FLUX DISTRIBUTION

FIGURE 7.6-12



ACAD 2070613

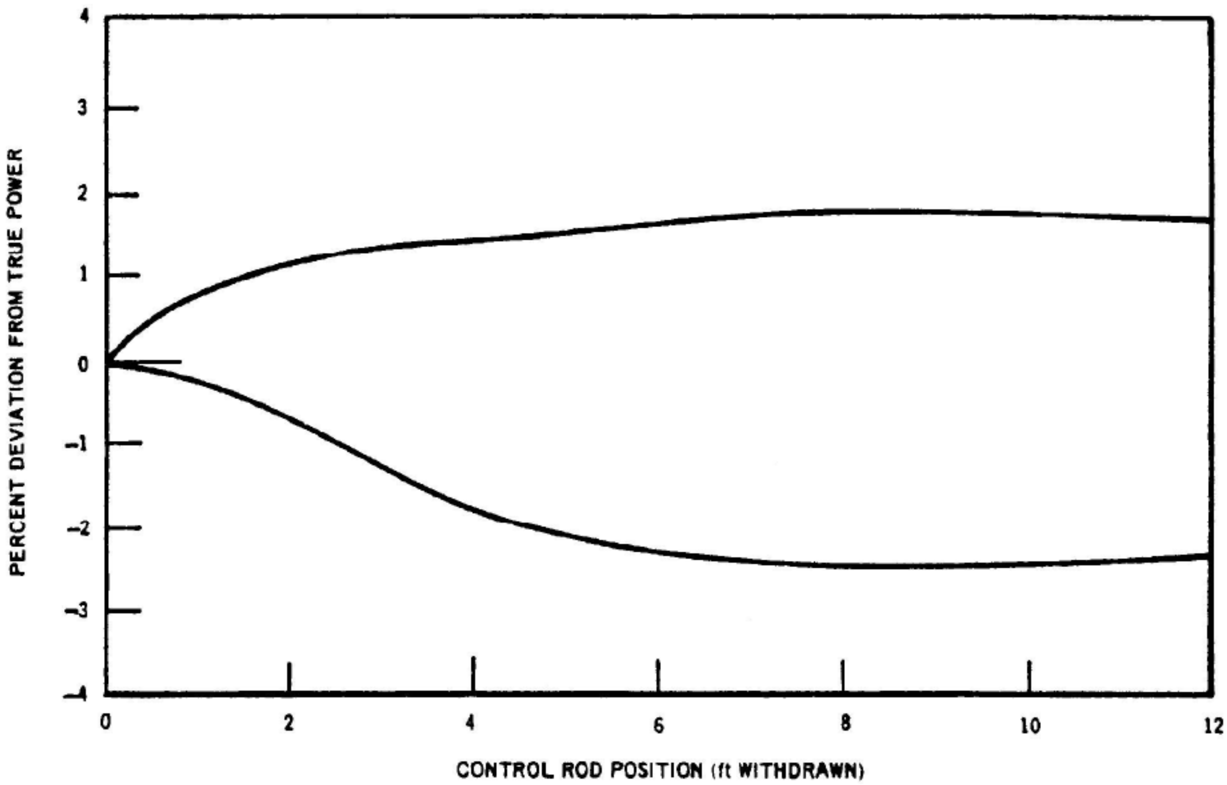
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ENVELOPE OF MAXIMUM APRM DEVIATION BY FLOW CONTROL REDUCTION IN POWER

FIGURE 7.6-13



ACAD 2070614

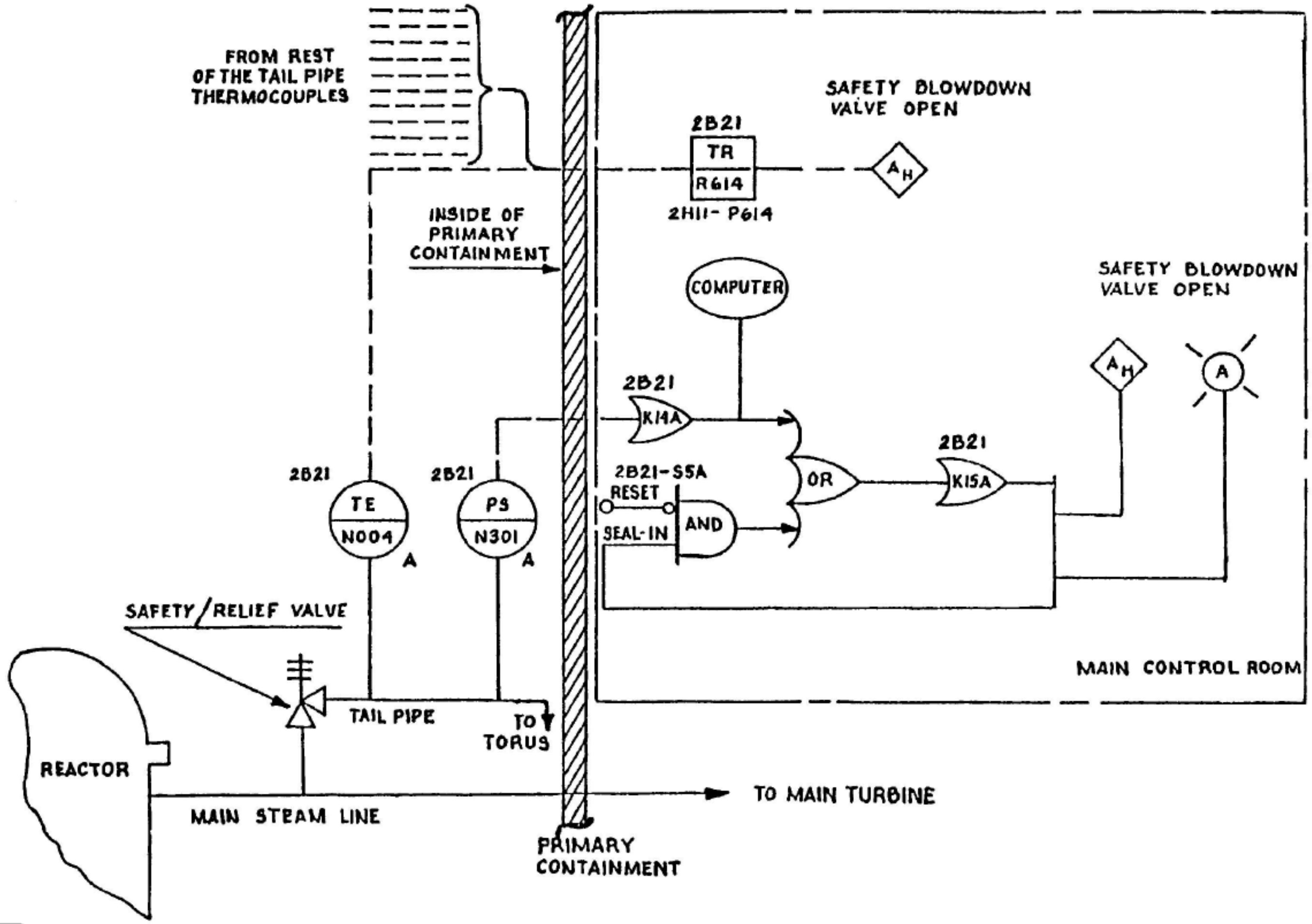
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

ENVELOPE OF MAXIMUM APRM DEVIATION FOR APRM TRACKING WITH ON-LIMITS CONTROL ROD WITHDRAWAL

FIGURE 7.6-14



ACAD 2070615

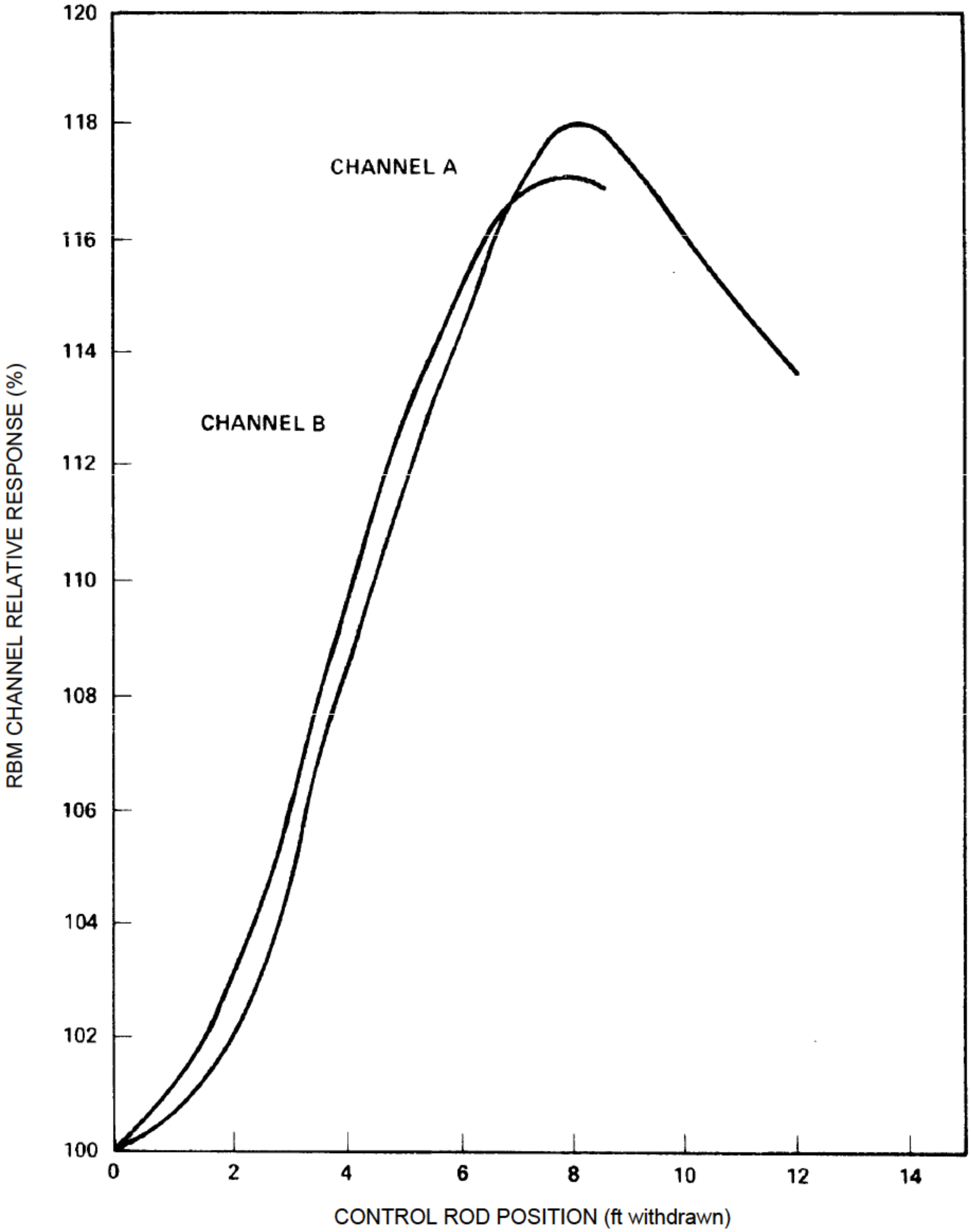
REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SIMPLIFIED SCHEMATIC OF
SRV POSITION INDICATION SYSTEM

FIGURE 7.6-15



ACAD 2070616

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL RBM CHANNEL RESPONSES
(NO FAILED LPRMs)

FIGURE 7.6-16

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

This section discusses control systems whose functions are not essential for the safety of the plant and provides a description of the interface between these systems and the safety-related systems. These systems are the reactor manual control system (RMCS), recirculation flow control system (RFCS), feedwater control system (FCS), and pressure regulator and turbine-generator control system.

7.7.1 REACTOR MANUAL CONTROL SYSTEM

The objective of the RMCS is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

7.7.1.1 Design Basis

The RMCS is designed to:

- Inhibit control rod withdrawal following erroneous control rod manipulations so that reactor protection system (RPS) action (scram) is not required.

- Inhibit control rod withdrawal in time to prevent local fuel damage as a result of erroneous control rod manipulation.

- Inhibit rod movement whenever such movement would result in operationally undesirable core reactivity conditions or whenever instrumentation (due to failure) is incapable of monitoring the core response to rod movement.

- Require deliberate operator action to effect a continuous rod withdrawal, thus limiting the potential for inadvertent rod withdrawals leading to RPS action.

- Provide the operator with the means to achieve prescribed control rod patterns by providing information pertinent to the position and motion of the control rods.

7.7.1.2 System Description

The RMCS consists of the electrical circuitry, switches, indicators, and alarm devices provided for operational manipulation of the control rods and the surveillance of associated equipment. This system includes the interlocks that inhibit rod movement (rod block) under certain conditions. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor; these devices are discussed in section 7.2. Neither are the mechanical devices of the control rod drives (CRDs) nor the control rod drive hydraulic system (CRDHS) included in the RMCS. These mechanical components are described in subsection 4.2.3.

Drawing nos. H-24717 through H-24720, H-24781, H-24782, H-24784, and H-24787 show the functional arrangement of devices for the control of components in the CRDHS. Although the drawings show the arrangement of scram devices, these devices are not part of the RMCS.

Control rod movement is accomplished by admitting water under pressure from a CRD water pump into the appropriate end of the CRD cylinder. The pressurized water forces the piston, which is attached by a connecting rod to the control rod, to move. Three modes of control rod operation are used: insert, withdraw, and settle. Four solenoid-operated valves are associated with each control rod to accomplish the actions required for the various operational modes. The valves control the path that the CRD water takes to the cylinder. The RMCS controls the valves.

Two of the four solenoid-operated valves for a control rod are electrically connected to the insert bus. When the insert bus is energized and when a control rod has been selected for movement, the two insert valves for the selected rod open, allowing the CRD water to take the path that results in control rod insertion. Of the two remaining solenoid-operated valves for a control rod, one is electrically connected to the withdraw bus, and the other is connected to the settle bus. The withdraw valve that connects the insert drive water supply line to the exhaust water header is one that is connected to the settle bus. When both the withdraw bus and the settle bus are energized and when a control rod has been selected for movement, both withdraw valves for the selected rod open, allowing CRD water to take the path that results in control rod withdrawal.

The settle mode is provided to ensure that the CRD index tube is engaged promptly by the collet fingers after the completion of either an insert or withdraw cycle. During the settle mode, the withdraw valve connected to the settle bus is opened or remains open while the other three solenoid-operated valves are closed. During an insert cycle, the settle action vents the pressure from the bottom of the CRD piston to the exhaust header, thus gradually reducing the differential pressure across the drive piston of the selected rod. During a withdraw cycle, the settle action again vents the bottom of the CRD piston to the exhaust header while the withdraw drive water supply is shut off. This also allows a gradual reduction in the differential pressure across the CRD piston. After the control rod has slowed down, the collet fingers engage the index tube and lock the rod in position. (See drawing no. H-24717 for valve sequence and timing.)

The arrangement of control rod selection pushbuttons and circuitry permits the selection of only one control rod at a time for movement. A rod is selected for movement by depressing a button for the desired rod on the reactor control benchboard in the main control room (MCR). This benchboard is shown on drawing nos. A-21603 (sheets 1-18), H-51307, S-26984, and S-26986. The direction in which the selected rod moves is determined by the position of a switch, called the "rod movement" switch, which is also located on the reactor control benchboard. This switch has rod-in and rod-out-notch positions and returns by spring action to the off position. The rod selection circuitry is arranged so that a rod selection is sustained until either another rod is selected or separate action is taken to revert the selection circuitry to a no-rod-selected condition. Initiating movement of the selected rod prevents the selection of any other rod until the movement cycle of the selected rod has been completed. Reversion to the no-rod-selected condition is not possible (except for loss of control circuit power) until any moving rod has completed the movement cycle.

<u>Insert Cycle</u>

The following is a description of the detailed operation of the RMCS during an insert cycle. The cycle is described in terms of the insert, withdraw, and settle buses. The response of a selected rod when the various buses are energized has been explained previously. Drawing nos. H-24719 and H-24720 can be used to follow the sequence of an insert cycle.

A three-position rod movement switch is provided on the reactor control benchboard. The switch has a rod-in position, a rod-out-notch position, and an off position. The switch returns by spring action to the off position. With a control rod selected for movement, placing the rod movement switch in the rod-in position and then releasing the switch energizes the insert bus for a limited amount of time. Just before the insert bus is deenergized, the settle bus is automatically energized and remains energized for a limited period of time after the insert bus is deenergized. The insert bus time setting and rate of drive water flow provided by the CRDHS determines the distance traveled by a rod. The timer setting results in a one-notch (6 in.) insertion of the selected rod for each momentary application of a rod-in signal from the rod movement switch. Continuous insertion of a selected rod is possible by holding the rod movement switch in the rod-in position.

A second switch can be used to initiate insertion of a selected control rod. This switch is in the rod-out-notch-override (RONOR) switch. The RONOR switch has three positions:

- Emergency-in.
- Notch override.
- Off.

The switch returns to the off position by spring action. By holding the RONOR switch in the emergency in position, the insert bus is continuously energized, causing a continuous insertion of the selected control rod.

<u>Withdraw Cycle</u>

The following is a description of the detailed operation of the RMCS during a withdraw cycle. The cycle is described in terms of the insert, withdraw, and settle buses. The response of a selected rod when the various buses are energized has been explained previously. Drawing nos. H-24719 and H-24720, can be used to follow the sequence of a withdraw cycle.

With a control rod selected for movement, placing the rod movement switch in the rod-out-notch position energizes the insert bus for a short period of time. Energizing the insert bus at the beginning of the withdrawal cycle is necessary to allow the collet fingers to disengage the index tube. When the insert bus is deenergized, the withdraw and settle buses are energized for a controlled period of time. The withdraw bus is deenergized prior to the settle bus, which when deenergized completes the withdraw cycle. This withdraw cycle is the same whether the rod movement switch is held continuously in the rod-out-notch position or released. The timers that control the withdraw cycle are set so that the rod travels one notch (6 in.) per cycle. (Provisions are included to prevent further control rod motion in the event of timer failure.) A selected

control rod can be continuously withdrawn if the rod movement switch is held in the rod-out-notch position at the same time that the RONOR switch is held in the notch-override position. With both switches held in these positions, the withdraw bus is continuously energized.

CRDHS Control

Two motor-operated pressure control valves, one air-operated flow control valve, and two solenoid-operated stabilizing valves are included in the CRDHS to maintain smooth and regulated system operation. (See subsection 4.2.3.) The motor-operated pressure control valves are positioned by manipulating switches in the MCR. The switches for these valves are located close to the pressure indicators that respond to the pressure changes caused by movements of the valves. The air-operated flow control valve is automatically positioned in response to signals from an upstream flow measuring device. The stabilizing valves are automatically controlled by the action of the energized insert and withdraw buses. The control scheme is shown on drawing nos. H-24718 through H-24720. The two drive water pumps are controlled by switches in the MCR. Each pump automatically stops upon indication of low suction pressure (drawing no. H-24718).

Rod Block Interlocks

Drawing nos. H-24719, H-24720, and H-24781 show the rod block interlocks used in the RMCS. Drawing nos. H-24719 and H-24720 show the general functional arrangement of the interlocks, and figure 7.6-1, sheet 1, and drawing no. H-24781 show the rod blocking functions that originate in the neutron monitoring system (NMS) in greater detail.

To achieve an operationally desirable performance objective where most failures of individual components would be easily detectable or do not disable the rod movement inhibiting functions, the rod block logic circuitry is arranged as two similar logic circuits. The two logic circuits are energized when control rod movement is allowed. Each logic circuit receives input trip signals from a number of trip channels, and each logic circuit can provide a separate rod block signal to inhibit rod withdrawal.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even if a continuous rod withdrawal is in progress.

The components used to initiate rod blocks in combination with refueling operations provide rod block trip signals to these same rod block circuits. These refueling rod blocks are described in subsection 7.6.1.

Rod Block Bypasses

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

- One source range monitor (SRM) channel.
- Two intermediate range monitor (IRM) channels (one on either bus A or bus B).
- One average power range monitor (APRM) channel.
- One rod block monitor (RBM) channel.

The IRM bypasses are arranged as two groups of equal numbers of channels. One manual bypass is allowed in each group. The groups are chosen so that adequate monitoring of the core is maintained with one channel bypassed in each group. The arrangement allows the bypassing of one IRM in each rod block logic circuit.

These bypasses are effected by positioning switches in the MCR. A light in the MCR indicates the bypassed condition.

An automatic bypass of the SRM detector position rod block is effected as the neutron flux increases beyond a preset low level on the SRM instrumentation. The bypass allows the detectors to be partially or completely withdrawn as a reactor startup is continued.

An automatic bypass of the RBM rod block occurs whenever the power level is below 30% core thermal power level or a peripheral control rod is selected. Either of these two conditions indicates violation of the fuel-cladding integrity safety limit is not threatened and RBM action is not required.

The rod worth minimizer (RWM) rod block function, when not in the sequence control mode, is automatically bypassed when reactor power increases above a preselected value in the power range. It may be manually bypassed for maintenance at any time.

Arrangement of Rod Block Trip Channels

The same grouping of NMS equipment (IRM, SRM, and RBM) that is used in the RPS is also used in the rod block circuitry. One-half of the total number of IRM, SRM, and RBM provide inputs to one of the rod block logic circuits, and the remaining halves provide inputs to the other logic circuit.

Scram discharge volume high water level signals are provided as inputs into both of the rod block logic circuits. Both rod block logic circuits sense when the high water level scram trip for the scram discharge volume is bypassed. The rod withdrawal block the RWM trip affects both rod block logic circuits. The rod insert block from the RWM function prevents energizing the insert bus for both notch insertion and continuous insertion.

The APRM and RBM rod block settings are varied as a function of recirculation flow and core thermal power, respectively. Analyses show that the settings selected are sufficient to avoid both RPS action and violation of the fuel integrity safety limit as a result of a single control rod withdrawal error. Mechanical switches in the SRM and IRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted. Additional detail on all the NMS trip channels is available on subsection 7.6.2. The rod block from scram discharge volume high water level uses two nonindicating float switches installed on the scram discharge volume.

<u>Control Rod Information Displays</u>

The operator has three different displays of control rod position:

- Rod status display.
- Four-rod display.
- Process computer printout.

These displays serve the following purposes:

- Provide the operator with a continuously available, easily understood presentation of each control rod's status.
- Provide continuously available, easily discernible warning of an abnormal condition.
- Present numerical rod position for each four-rod group.
- Log all control rod positions on a routine basis.

The rod status display is located on a control board in the MCR. It provides the following continuously available information for each individual rod:

- Rod fully inserted (green).
- Rod fully withdrawn (red).
- Rod identification (coordinate position of selected rod, white).
- Accumulator trouble (amber).
- Rod scram (blue).
- Rod drift (red).

Operator display assemblies include the LPRM values for each detector arrays surrounding the rod selected. Four modules display rod position in two digits and rod selected status (white light, off or on) for the four rods located within the LPRM detector arrays being displayed. The rod position digital range is from 00 to 48, with 00 representing the fully in position and 48, fully out; each even increment; i.e., 00-02, equals 6 physical inches of rod movement. The four-rod display allows the operator to easily focus his attention on the core volume of concern during rod movements.

Control rod position information is obtained from reed switches in the CRD that open or close during rod movement. Reed switches are provided at each 3-in. increment of piston travel. Since a notch is 6 in., indication is available for each half-notch of rod travel. The reed switches located at the half-notch positions for each rod are used to indicate rod drift. Both a rod selected for movement and the rods not selected for movement are monitored for drift. A drifting rod is indicated by an alarm and red light in the MCR. The rod drift condition is also monitored by the process computer.

Reed switches are also provided at locations that are beyond the limits of normal rod movement. If the rod drive piston moves to these overtravel positions, an alarm is sounded in the MCR. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact, because with the coupling in its normal condition, the drive cannot be physically withdrawn to the overtravel position. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position.

The process computer receives position indication from each rod and prints out all rod positions in a pre-arranged sequence. The operator may order a computer printout anytime it is desired by dialing the correct program (two digits) and pushing the printout button. The printout depicts the rod positions in an array corresponding to the other displays and actual core location. The printout is always in the same order; if there is an incorrect input, the printout signifies it by printing either a blank or 99.

All displays are essentially independent of one another. Signals for the rod status display are hard wired from the rod position information system cabinet buffer outputs, so that a signal failure of other parts of the rod position information system cabinet do not affect this display. Likewise, the computer could conceivably fail and the rod status and rod position displays continue to function normally.

The following MCR lights or alarms are provided to allow the operator to know the conditions of the CRDHS and the control circuitry (drawing nos. H-24717 and H-24718):

- Stabilizing valve selector switch position.
- Insert bus energized.
- Withdraw bus energized.
- Settle bus energized.

- Withdrawal not permitted.
- Notch override.
- Pressure control valve position.
- Flow control valve position.
- Drive water pump low suction pressure.
- Drive water filter high differential pressure.
- Charging water (to accumulator) high pressure.
- CRD temperature.
- Scram discharge volume not drained.
- Scram valve pilot air header high/low pressure.

7.7.1.3 Analysis

The following analysis demonstrates that the RMCS is not required for safety or reactor shutdown.

The circuitry described for the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The scram circuitry is discussed in section 7.2. Because each control rod is controlled as an individual unit, a failure that results in energizing of any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod. No single failure in the RMCS can result in the prevention of a reactor scram. Repair, adjustment, or maintenance of RMCS components does not affect the scram circuitry.

The RMCS can be routinely checked for proper operation by manipulating control rods using the various methods of control. Detailed testing and calibration can be performed by using standard test and calibration procedures for the various components of the reactor manual control circuitry.

Drawing nos. H-24718 and H-24726 show the rod block initiation functions. Drawing nos. H-24723 and H-24727 show the rod block functions initiated in the NMS. The channel A and B annunciating rod block control and nonannunciating rod block control shown on drawing no. H-24719 initiate rod blocks in the RMCS as indicated on drawing nos. H-24718 and H-24719. Following is a discussion of the rod block functions and their circuitry. The operability requirements of these functions are specified in the Technical Specifications and the Technical Requirements Manual.

A. With the mode switch in SHUTDOWN, no control rod can be withdrawn. This enforces compliance with the intent of the Shutdown mode.

B. The circuitry is arranged to initiate a rod block regardless of the position of the mode switch for the following conditions:

1. Any APRM upscale rod block alarm. The purpose of this rod block function is to avoid conditions that would require RPS 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.

2. 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 properly bypassed.

3. Either RBM upscale alarm. This function is provided to stop the erroneous withdrawal of a single worst-case control rod so that violation of the fuel integrity safety limit does not result. Although local fuel damage poses no significant threat in terms of radioactive material released from the nuclear system, the alarm setting is selected so that no violation of the fuel integrity safety limit results from a single control rod withdrawal error during power range operation.

4. Either RBM inoperative alarm. This assures that no control rod is withdrawn unless the RBM channels are in service or properly bypassed.

5. Scram discharge volume high-water level. This assures that no control rod is withdrawn unless enough capacity is available in the scram discharge volume to accommodate a scram. The setting is selected to initiate a rod block well in advance of that level which produces a scram.

6. Scram discharge volume high-level scram trip bypassed. This assures that no control rod is withdrawn while the scram discharge volume high-water level scram function is out of service.

7. The RWM initiates a rod insert and withdraw block. The purpose of this function is to reinforce procedural controls that limit there activity worth of control rods under low-power conditions. The rod block trip settings are based on the allowable control rod worth limits established for the design basis rod drop accident. Adherence to prescribed control rod patterns is the normal method by which this reactivity restriction is observed. Additional information on the RWM function is available in section 7.10.

8. Rod position information system malfunction. This assures that no control rod can be withdrawn unless the rod position information system is in service.

9. Rod movement timer switch malfunction during withdrawal. This assures that no control rod can be withdrawn unless the timer is within specifications.

C. With the mode switch in RUN, the following conditions initiate a rod block:

1. Any APRM downscale alarm. This assures that no control rod is withdrawn during power range operation unless the average power range neutron monitoring channels are operating properly or are correctly bypassed. All unbypassed APRMs must be onscale during reactor operation in the RUN mode.

2. Either RBM downscale alarm. This assures that no control rod is withdrawn during power range operation unless the RBM channels are operating properly or are correctly bypassed. Unbypassed RBM must be onscale during reactor operations in the RUN mode.

D. With the mode switch in STARTUP or REFUEL, the following conditions initiate a rod block:

1. Any SRM detector not fully inserted into the core when the SRM count level is below the retract permit level and any IRM range switch on either of the two lowest ranges. This assures that no control rod is withdrawn unless all SRM detectors are properly inserted when they must be relied upon to provide the operator with neutron flux level information. This function is not required if the detector is verified to be in the fully inserted position and the drive motor is deactivated.

2. Any ARM upscale level alarm. This assures that no control rod is withdrawn unless the SRM detectors are properly retracted during a reactor startup. The rod block setting is selected at the upper end of the range over which the SRM is designed to detect and measure neutron flux.

3. Any SRM downscale alarm. This assures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring.

4. Any SRM inoperative alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all ARM channels are in service or properly bypassed.

5. Any 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 in that all IRM detectors are properly located. This function is not required if the detector is verified to be in the fully inserted position and the drive motor is deactivated.

6. Any IRM upscale alarm. This assures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is properly upranged during a reactor startup. This rod block also provides a means to stop rod withdrawal in time to avoid conditions requiring RPS action (scram) in the

event that a rod withdrawal error is made during low neutron flux level operations.

7. Any IRM downscale alarm except when range switch is on the lowest range. This assures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being properly monitored. This rod block prevents the continuation of a reactor startup if the operator up-ranges the IRM too far for the existing flux level; thus, the rod block ensures that the IRM is onscale if control rods are to be withdrawn.

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

E. Refer to paragraph 7.7.1.2 for rod block bypasses.

The RMCS is an operational system used for regulating power level and power distribution. This system is self-monitoring with the automatic rod blocks, operator annunciators, and operating status lights (such as the rod position indicators) as part of the system design. The rod blocks are an internal subsystem of this nonsafety system and as such are designed to be single-failure proof but are not designed to stringent safety standards.

The RMCS receives rod block signals from the NMS to prevent improper rod motion which could result in reactor scram. Common LPRM, IRM, and SRM detectors are used, but the signal is physically and electrically isolated before use in the RMCS. This isolation is achieved through two separate relay trip units which prevent any feedback from the RMCS to the RPS.

The performance of the RMCS is monitored by the RPS. If a variable (for example, neutron flux) which is controlled by the RMCS exceeds specific limits, the RPS takes independent action to cause reactor shutdown.

The safety analysis in chapter 15 shows that failures in the RMCS, such as continuous withdrawal of a control rod, do not result in any fuel damage. No fuel damage results from any single operator error or single equipment malfunction.

Conformance to General Design Criterion 24

No part of the RMCS is required for scram. The rod block functions provided by the NMS are the only instances where the RMCS uses any instruments or devices used by the RPS. The rod block signals received from the NMS prevent improper rod motion before limits causing reactor scram are reached. Common LPRM, IRM, and SRM detectors are used, but physically and electrically separate trip units provide signals for the RMCS and RPS.

7.7.2 RECIRCULATION FLOW CONTROL SYSTEM

The objective of the RFCS is to control reactor power level over a limited range by controlling the flowrate of the reactor recirculating water.

7.7.2.1 Design Basis

The RFCS functions so that no anticipated operational occurrence (AOO) resulting from a malfunction in the RFCS can result in damaging the fuel or exceeding nuclear system pressure limits. The RFCS is designed to allow both manual and automatic recirculation flow adjustment, thereby enabling manual control of reactor power level and automatic load following. The automatic load-following capability is not used at Plant Hatch.

7.7.2.2 System Description

Each recirculation pump is started and accelerated to a speed equal to 22% of rated speed with the discharge valve closed. The discharge valve is opened and the flow increased by increasing pump speed.

Depending on whether the unit is operating in one recirculation loop operation or two recirculation loop operation, reactor recirculation flow is changed by adjusting the speed of one or both of the two reactor recirculation pumps. The RFCS controls the power supplies to the recirculation pump motors by adjusting the frequency of the electrical power supplies to the recirculation pump motors. Thus, the RFCS can effect changes in reactor power level.

The power control range is approximately a constant fraction of operating power but a variable absolute power range. A lower limit exists on flow control capability, below which control by flow is not permitted.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. The additional neutron moderation increases the reactivity of the core, which causes the reactor power level to increase. The increased steam generation rate increases the steam volume in the core with a consequent negative reactivity effect, and a new steady-state power level is established. When recirculation flow is reduced, the power level is reduced.

Drawing nos. H-24713 through H-24716 and H-24760 illustrate how the RFCS operates in conjunction with the turbine controls.

Each recirculation pump motor has its own adjustable speed drive (ASD) for a power supply. To change the speed of the reactor recirculation pump, the ASD varies the frequency and magnitude of the voltage supplied to the pump motor to give the desired pump speed. A manually set signal from the master controller (manual speed control pushbutton switches in the MCR) adjusts the speed setting of the speed control system for each ASD.

The reactor power change resulting from the change in recirculation flow causes the initial pressure regulator to reposition the turbine control valves.

Adjustable Speed Drive

Each ASD supplies power to its associated recirculating pump motor. Each of the two ASDs and its controls are identical; therefore, only one description is given of the ASD. The ASD can continuously supply power to the pump motor at any speed between ~ 345 rpm and 1830 rpm. However, the ASD controls limit the minimum pump speed to ~ 366 rpm (includes motor slippage). The maximum pump speed is limited so as not to exceed the maximum allowable core flow. Overfrequency relays that monitor ASD output frequency will trip the ASD as a backup to the ASD controller maximum speed limiter. The ASD is capable of starting the pump and accelerating it from standstill to the desired operating speed when the pump motor thrust bearing is fully loaded by reactor pressure acting on the pump shaft.

The main components of the ASD, described below, are an input power cabinet, a transformer cabinet, fuse/precharge/control (FPC) cabinet, a cell cabinet, an output power cabinet, a relay cabinet, and a coolant cabinet.

A. Input Power Cabinet

The input power cabinet contains terminals for incoming power cables, potential and current transformers, and instrumentation for input voltage signal conditioning for internal controls. The stainless steel ground pads are welded to the cabinet.

B. Transformer Cabinet

The transformer cabinet consists of a power transformer which acts as an isolation transformer with four secondaries per phase. The phase angle of the four secondaries differs in phase angle by 15 degrees. The transformer primary and secondary windings are built using copper tubing with drive coolant flowing through the tubing.

C. Fuse/Precharge/Control (FPC) Cabinet

The control interface for the ASD is comprised of hardwired analog and digital inputs and outputs signals and serial interface for plant safety parameter display system (SPDS) and the ASD PLC system. The serial interface will utilize industry standard control interface data highway protocol. The serial interface will allow transfer of data such as for status, monitoring, alarm, historic, and diagnostic information. Critical signals required for the control of the ASD will be hard wired. Additionally, the ASD will provide a local emergency stop button, a local remote selector switch, a local display of key operating parameters, and alarms.

D. Cell Cabinet

The cell cabinet contains 12 power cells, 4 per phase, which are a static pulse width modulated (PWM) power converter. Each power cell consists of a three-

phase diode rectifier fed by one of the secondaries and capacitors. The rectifier charges the capacitor bank that feeds a single-phase bridge of four insulated gate bipolar transistors (IGBT), which generate the PWM output of the power cells. The phase shifted secondaries cause harmonic cancellation between the reflected secondary currents.

E. Output Power Cabinet

The output power cabinet houses the output medium voltage line terminals and stainless-steel ground pads. The output line current and voltage transformers are also included in the output power cabinet.

F. Relay Cabinet

The ASD system will include various protection features for the internal components, and protection for the motor connected to its power output. The motor protection provided in the ASD will include protection against overvoltage, overspeed, motor ground fault, motor thermal overload, instantaneous overcurrent, open output phase, and torque limit. The protective relays are configured in two-out-of-three trip logic to preclude single-point failure.

G. Coolant Cabinet

The ASD transformer and power cells require supplemental cooling. An external liquid-to-liquid heat exchanger provides the required cooling. This arrangement requires providing 600-V power sources to two cooling pumps mounted in the cooling cabinet. The cabinet houses a PLC-based control system with a human machine interface (HMI), a coolant pump control mode selector switch, and a coolant pump hand mode selector switch. The PLC control system for the cooling system is connected via a redundant network to the ASD PLC control system.

<u>Speed Control Components</u>

The speed control system controls the output frequency and voltage of each ASD. The ASDs can be manually controlled individually or jointly. The master controller described below is common to the control of both ASDs. The signals from the master controller are fed to two separate sets of control system components, one set for each ASD. The control system components for each ASD described below are a master controller and ASD controller.

A. Master Controller

The master controller provides signals to each ASD controller to increase/decrease speed incrementally via manual pushbutton switches located in the MCR to manually control both recirculation pumps.

During system operation, the master controller sends a signal output to the ASD controller to limit ASD output frequency if either the recirculation pump discharge valve is not fully open or total feedwater flow is < 20% of rated flow. This limiting

action prevents pump overheating should the discharge valve be closed and protects the recirculation pump against possible cavitation due to low feedwater flow.

The master controller will also send an output signal to the ASD controller to limit ASD output frequency on any of the following conditions:

- If any one feedwater pump trips, and either a low-level alarm is initiated or total steam flow is greater than the capacity of a single reactor feed pump, recirculation speed is reduced to allow the resultant reactor power to remain within the capabilities of the feedwater system.

- Low vessel level results in a recirculation speed reduction to avoid a reactor scram from other feedwater transients.

- Inadequate net positive suction head (NPSH) at a condensate booster pump or reactor feed pump suction results in a recirculation flow runback, reducing core flow to prevent tripping of a condensate booster pump or reactor feed pump.

- Upon indication of a scram, as determined by changes in the vessel level and steam flow signals, recirculation flow is run back to limit water level shrink following the scram.

B. ASD Controller

The ASD controller initiates all ASD output frequency changes and controls all speed change ramp rates. Initial ASD start to minimum pump speed and ASD shutdown are also controlled by the ASD controller. Abnormal conditions affecting the ASD are alarmed in the MCR.

7.7.2.3 <u>Analysis</u>

There are no specific regulatory requirements for the RFCS. The RFCS is not a safety-related system and is not required for safe shutdown of the plant, nor is it required during or after accident conditions.

The RFCS functions so that no AOO resulting from a malfunction in the RFCS can result in damaging the fuel or exceeding the nuclear system pressure limits. The coastdown inertia of the equipment consists of only the recirculation motor and pump.

The safety analysis (chapter 15) shows that no malfunction in the RFCS can cause a transient sufficient to damage the fuel barrier or exceed the nuclear system pressure limits.

Each ASD control system and the master controller are functioning during normal power operation. Any abnormal operation of these components can be detected during operation. The

components which do not continually function during normal operation can be tested and inspected during scheduled plant shutdowns. All the RFCS components are tested and inspected according to the component manufacturer's recommendations.

7.7.3 FEEDWATER CONTROL SYSTEM

The FCS, during normal (0-100%) plant operation, automatically regulates feedwater flow into the RPV. The system is capable of being manually operated. An IED for the FCS is provided on drawing no. H-26991.

7.7.3.1 Design Basis

The FCS is designed to regulate the feedwater flow so that the proper water level in the reactor vessel is maintained according to the requirements of the steam separators and to prevent uncovering of the reactor core over the entire power range of the reactor.

7.7.3.2 System Description

The feedwater flow control instrumentation measures the water level in the RPV, the feedwater flowrate into the RPV, and the steam flowrate from the RPV. During automatic operation, these three measurements are used for controlling feedwater flow.

The optimum RPV water level is determined by the requirements of the steam separators which limit the water carryover with the steam going to the turbines and limit the steam carryunder with the water returning to the core. For optimum limitation of carryover and carryunder, the steam separators require a decrease in RPV water level as a function of an increase in reactor power level. The water level in the RPV is maintained within ± 2 in. of the optimum level. This control capability is achieved during plant load changes by balancing the mass flowrate of feedwater to the RPV with the steam flow from the RPV. The feedwater flow regulation is achieved by adjusting the speed of the turbine-driven feedwater pumps.

RPV Water Level Measurement

RPV water level is measured by two independent sensing systems composed of three sensing systems. A differential pressure transmitter senses the difference between the pressure due to a constant reference column of water and the pressure due to the variable height of water in the RPV. This differential pressure transmitter is installed on lines that serve other systems, subsection 7.6.7. Each of these transmitters is powered by an independent power source. The median signal is selected from these level measurements by a programmable computing station. This median level signal is used by the master level controller as its primary input. One of the three level signals is also sent to the master level controller without passing through the median selector. This signal is used for control if the median signal is not available due to a module failure or a loss of power to the median selector. The operator is able to manually bypass the median level and use the selected level signal as the control input. Each individual level measurement is compared to the median signal and a deviation alarm will be generated if

a wide deviation (> 5 in.) is sensed. The RPV water level and pressure from each sensing system are indicated in the MCR. The median water level and the selected RPV pressure signals are continually recorded in the MCR. A separate level-sensing loop provides a signal in the MCR to indicate RPV water level in the overfill range.

Steam Flow Measurement

The steam flow is sensed at each main steam line flow restrictor by a differential pressure transmitter. Programmable computing modules perform the square root function, multiplication by the flow constant, and sum the flow signals. The total steam flow signal is sent to the process computer, the control panel recorder, and master level controller.

The individual flow signals are sent to the emergency response facility and to control panel indicators. The individual steam flows are compared to the average and a deviation (greater than a preset value) will generate an alarm condition. Digital outputs indicating a steam deviation are processed with the feedwater flow deviation alarm to provide a digital input to the master level controller (MLC) denoting a bad quality input. This bad quality input will trigger the master level controller to switch to single element control.

Feedwater Flow Measurement

Feedwater flow is sensed at a flow element in each feedwater line by differential pressure transmitters. A programmable computing module performs the square root function, multiplication by the flow constant, and sums the two flow signals. The individual flow signals are sent to the emergency response facility, to the process computer and to control panel indicators. Total feedwater flow is also recorded in the MCR. Total feedwater flow is monitored to provide low feedwater flow digital outputs to the reactor recirculation pumps.

The two feedwater flow signals are compared. A deviation between measurements greater than a preset value or an individual bad quality will generate a deviation alarm.

Digital inputs and failure indications from the steam flow signal processors along with the feedwater flow deviation alarm are used to produce a digital output indicating a bad quality flow input or processor failure which is sent to the MCL. The MCL will switch to single element control upon the receipt of a digital signal representing either bad feedwater flow or steam flow signal. A new indicating light indicates when the controller is in the three-element mode.

Feedwater Control Signal

The following components are operated manually or automatically to produce the feedwater control signal:

A. Master Level Controller

The MLC performs either single-element or three-element control based on which is selected by the operator and the status of the digital input from the feedwater flow signal processor. The MLC will only switch to three-element control when it is selected by the operator and the status of the three-element enable signal from the

feedwater flow signal processor is positive (close contact). If the three-element enable signal goes negative when the MLC is controlling in three-element, the MLC will switch to single element control. After restoration of the failed signal, the operator must reset the condition by first positioning the mode selector switch to single element and then changing to three-element mode.

The MLC uses the median level signal as its primary input if the operator has selected this mode. However, if the median selector module fails the MLC will switch to the backup level signal. This signal (from transmitter A, B, or C) is selected by the operator using the control panel switch.

B. Manual/Automatic Transfer Station (One For Each FCS)

The M/A transfer station is a manual controller with a transfer switch and output indicator. While each system is being controlled by the level controller, the transfer switch is positioned so that the manual controller is bypassed and the level controller signal goes through to control the feedwater pump turbines. During startup or when manual control is desirable, the level controller signal is blocked by the transfer switch and the feedwater control signal is provided at the M/A transfer station by the operator.

M/A stations will assume control of RPV water level in single-element control using the backup level signal upon the failure of the MLC or the loss of signal from the MLC. If the M/A station enters this backup mode, it will continue in this mode until the M/A station is transferred to manual and back to auto. The other M/A station will switch to manual and hold its output if its power is still available. If power to an M/A station is lost, the RFPT speed controller will switch to its manual mode. If this occurs the RFPT speed may be changed by the operator using the speed setter switch on the MCR panel.

Normal Automatic Operation

The ability of the FCS to maintain RPV water level within a small margin of optimum water level during plant load changes is accomplished by the three-element control signal. The three-element control is executed as follows: The difference between the total steam flow and the total feedwater flow is added to the reactor level signal. This sum is used as an input by the control algorithm to provide the final control signal. If steam flow is greater than feedwater flow, the output is increased from its normal value when steam and feedwater flows are equal. The reverse is also true.

Optional Automatic Operation

A single-element control signal (RPV water level) can be used to replace the above three-element signal. RPV water level is then controlled by the reactor level signal in accordance with the controller setpoint.

Auxiliary Functions

The three level signals provide a two-out-of-three logic to trip the reactor feedwater pumps on reactor high water level. The level control system also provides interlocks and control functions to equipment external to this system. The reactor recirculation system logic is as follows:

- If any one feedwater pump trips, and either a low-level alarm is initiated or a total steam flow is greater than the capacity of a single reactor feed pump, recirculation speed is reduced to allow the resultant reactor power to remain within the capabilities of the feedwater system.

- Low vessel level results in a recirculation speed reduction to avoid a reactor scram from other feedwater transients.

- Inadequate NPSH at a condensate booster pump results in a recirculation flow runback, reducing core flow to prevent tripping of a condensate booster pump or reactor feed pump.

- Upon indication of a scram, as determined by changes in the vessel level and steam flow signals, recirculation flow is run back to limit a water level shrink following the scram.

- Upon sustained low feedwater flow, reactor recirculation flow is reduced to ensure adequate NPSH for the recirculation system.

Turbine-Driven Feedwater Pump Controls

Feedwater is delivered to the reactor vessel by two turbine-driven feedwater pumps. The feedwater pumps operate in parallel. The turbines are normally driven by low-pressure steam supplied from the main turbine cross around steam line.
The turbine speed is controlled by an electrohydraulic system. During normal operation, the feedwater three-element control signal is fed to the control mechanism of each operating turbine. The turbine control mechanisms adjust the speed of the associated turbines so that feedwater flow is proportional to the feedwater control signal.

Inspection and Testing

All FCS components can be tested and inspected according to manufacturers' recommendations. This can be done prior to plant operation and during scheduled shutdowns. Reactor vessel water level indications from the three water level sensing systems can be compared during normal operation to detect instrument malfunctions. Steam mass flowrate and feedwater mass flowrate can be compared during constant load operation to detect inconsistencies in their signals. The level controller can be tested while the FCS is being controlled by the manual/automatic transfer stations.

Startup Control

During plant startup from low power a startup valve is used. The single element level signal is used with a separate level controller to regulate flow to the reactor. During the startup a differential pressure controller can be used to maintain a constant differential pressure across the startup valve by regulating the turbine speed. The pressure controller output to the turbine controls is by means of a third position on the one element - three element switch marked "differential pressure control."

7.7.3.3 Analysis

The FCS is not a safety-related system and is not required for safe shutdown of the plant, nor is it required during or after accident conditions. A loss of feedwater condition is discussed in chapter 15.

There is no interface with safety-related systems.

The following failure modes are handled by the control systems:

A. Loss of a Reactor Feed Pump Unit

A logic circuit detects the loss of feedwater flow through a pump caused by the trip of the auxiliary turbine drive of the reactor feed pump. The loss of a reactor feedwater pump and the subsequent or coincident low RPV water level results in a feedwater flow which is less than reactor demand. When this condition exists, a logic circuit limits reactor recirculation flow to match the available feedwater supply. This prevents an RPV low water level trip.

B. Reactor Recirculation Pump NPSH Protection

A logic circuit detects a reduction in total feedwater flow which could cause low NPSH and cavitation of the recirculation pumps. A limiter in each reactor recirculation flow control loop reduces the recirculation flow as required to prevent cavitation.

C. Rod Worth Minimizer Interlock

An alarm unit is provided to monitor total steam flow and feedwater flow. When the steam flow is reduced to the setpoint, an alarm is initiated; if either the steam flow or the feedwater flow is reduced to a second (lower) setpoint, an interlock automatically trips the control RWM circuit into the reactor manual rod control circuits.

D. Loss of Feedwater Control Signal

In the event of the loss of the control signal because of power supply failures and/or major component failures, a signal failure logic within the control system

locks the reactor feed pumps at the speed level demanded at the instant prior to control system failure. It is possible to operate the turbine speed controllers by remote manual controls until the control system failures have been resolved. Resetting of the feedwater control to automatic can be manually controlled from the control room operator's panel. A reactor feed pump turbine controller trouble alarm is provided in the MCR; an indicator pilot lamp is located at the control reset switch to indicate reset action is required when the lamp is illuminated.

E. Water Level and Steam Pressure Alarms

High and low water level alarms are derived from the reactor sensed water level recorder. A reactor steam dome high-pressure alarm is derived from the reactor wide-range pressure recorder. The alarms are continuously adjustable over the recorder scale ranges.

F. High RPV Water Level Trip

Redundant current operated trip relays, connected to each reactor level indicating and/or control channel, provide the required logic circuit to trip the main and auxiliary reactor feed pump steam turbines in the event of high RPV water level. The logic is based on two out of three channels to trip.

7.7.4 PRESSURE REGULATOR AND TURBINE-GENERATOR CONTROL SYSTEM

In conjunction with the reactor recirculation flow control system, the pressure regulator and turbine-generator control system maintains constant reactor pressure during normal operation and operates the steam bypass system such that ~ 20% of rated flow maintains constant reactor pressure during plant startup, shutdown, and normal operation.

7.7.4.1 Design Bases

The pressure regulator and turbine-generator control system is designed to accomplish the following control functions:

- Control speed and acceleration from zero to 110% speed with nominal speed reference settings at zero, 6%, 30%, 85%, 100%, and overspeed.
- Operate the steam bypass system to keep reactor within operating pressure.
- Control reactor pressure from 150 psig to 1055 psig, for startup to full power operation.
- Match nuclear steam supply to turbine steam requirements using the following functions:

- Adjustment of reactor recirculation system flow to satisfy load requirement as determined by the operator.

- Adjust the pressure reference of the pressure control unit in order to improve the load response of the plant.

7.7.4.2 System Description

Reactor pressure regulation and turbine-generator controls and protection are performed by the GE Speedtronic Mark VI electrohydraulic control (EHC) system. The Mark VI is a fully programmable, triple modular redundant (TMR) process control system, which couples GE's extensive steam turbine and BWR reactor control application and design experience with modern electronic hardware and software. This allows immediate access to all major control functions, extensive monitoring capabilities, and many built-in features that automatically protect the turbine-generator from a variety of abnormal operating conditions such as turbine overspeed, loss of oil pressure, and LP exhaust hood overheating.

The Mark VI controller performs the following basic turbine control and pressure regulation functions:

- Controlling turbine speed and acceleration through the entire speed range, including overspeed testing and protection.

- Controlling turbine megawatt production using the turbine control valves to regulate the steam flow.

- Maximum combined flow limiting based on total control valve and bypass valve position.

- Detecting and alarming abnormal conditions and events based on the interaction of external sensors and devices and the application code.

- Detecting dangerous/undesirable operating conditions which require tripping of the turbine.

- Self-monitoring of the Mark VI subsystems, including power supplies, redundant control circuits, and sensors.

- Controlling and supervising the operational testing of steam valves and turbine protective devices.

- Warming of the valve chest and high-pressure turbine section by pressurization while on turning gear.

- Regulating main steam (throttle) pressure as required by reactor power level from zero speed to full load. Pressure regulation is transferred to the bypass valves when the turbine-generator is flow or load setpoint limited.

- Automated reactor cooling using the bypass valves.

Normal operating control of the pressure regulator and turbine-generator control system is represented by the Mark VI BWR functional diagram (figure 7.7-3). The control system can be divided into subsystems designated as turbine controller and pressure controller (as shown in figure 7.7-3). The automatic load-following feature of the system is not used at Plant Hatch.

Following are the major functional components processed in the turbine controller:

- Controlling turbine speed.

- Controlling turbine load.

- Controlling and monitoring the steam flow control valves.

- Controlling turbine prewarming.

- Preventing an overspeed event.

- Protecting against unsafe operating conditions.

Following are the major functional components processed in the pressure controller:

- Controlling inlet pressure.

- Controlling and monitoring the turbine steam bypass system.

- Protecting against unsafe operating conditions.

- Controlling reactor cooldown.

7.7.4.3 Analysis

The pressure regulator and turbine-generator instrumentation controls are not safety related and are not required for the safe shutdown of the plant. Neither are they required during or after accident conditions.

The pressure regulator and turbine-generator control system are designed to provide a stable control response to normal load fluctuations.

The main turbine bypass valves are capable of responding to the maximum closure rate of the turbine control valves such that reactor steam flow is not significantly affected until the

magnitude of the load rejection exceeds the capacity of the bypass valves (21% of full load). Load rejections in excess of bypass valve capacity and plant auxiliary loads may cause the reactor to scram due to high pressure. Any condition causing the turbine stop valves to close directly initiates a scram before reactor pressure or neutron flux has risen to the trip level. Loss of electrical or hydraulic power causes all valves to close.

The AOO analyses and results for a component failure in the turbine-generator control system are provided in section 15.2.

The following are the turbine tripping functions:

A. Low bearing oil pressure.

B. Thrust bearing wear.

C. Low hydraulic fluid pressure.

D. Moisture separator high level.

E. High vibration - the Bently Nevada Vibration Monitoring System provides monitoring of turbine vibration level. The turbine is tripped by high vibration. Alarms are provided to annunciate in the MCR prior to the trip.

F. Loss of stator coolant.

G. Low shaft pump discharge pressure.

H. Loss of condenser vacuum.

I. Overspeed, backup overspeed, and manual - a description of these turbine trips is supplied in supplement 10.2A.

J. RPV water high level.

K. Main transformer differential - a main transformer differential overcurrent (primary and secondary) initiates a lockout switch to trip the turbine.

L. Auxiliary transformer 2A differential - an auxiliary transformer 2A differential overcurrent initiates a lockout switch to trip the turbine.

M. Auxiliary transformer 2B differential - an auxiliary transformer 2B differential overcurrent initiates a lockout switch to trip the turbine.

N. Main transformer fault - a main transformer fault pressure initiates a lockout switch to trip the turbine.

O. Auxiliary transformer 2A fault - an auxiliary transformer 2A fault pressure initiates a lockout switch to trip the turbine.

P. Auxiliary transformer 2B fault - an auxiliary transformer 2B fault pressure initiates a lockout switch to trip the turbine.

Q. Generator ground - a generator ground overcurrent initiates a lockout switch to trip the turbine.

R. Generator differential - a generator differential overcurrent initiates a lockout switch to trip the turbine.

S. Generator loss of excitation - a generator loss of excitation initiates a lockout switch to trip the turbine.

T. Generator underfrequency - a generator underfrequency condition initiates protective underfrequency relays which actuate an alarm and subsequently trip the turbine if generator frequency continues to decrease. Time delays are provided on both the alarm and tripping functions to prevent nuisance alarms and unnecessary turbine trips. The relays are configured in a two-out-of-two logic arrangement.

The pressure regulator and turbine-generator instrumentation and control is designed to maintain constant reactor pressure, to follow system load demand fluctuations and to control turbine speed. Excessive reactor pressure swings caused by failure of this system would be dealt with by the RPS (section 7.2) and/or the safety relief valves.

TABLE 7.7-1 (SHEET 1 OF 2)

RMCS INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Normal Range	Accuracy	Trip Setting
Drive water pressure (downstream)	Pressure indicator	0 - 1800 psig	± 1% full scale	
Drive water pressure (upstream)	Pressure indicator	0 - 1800 psig	± 2% full scale	
Drive water pump suction pressure	Pressure indicator	-15 to +50 psig	± 2% full scale	
Drive water filter differential pressure	Differential pressure switch (indicating)	0 - 100 psid	± 2% full scale	20 psid
Cooling water header pressure	Pressure indicator	0 - 1800 psig	± 1% full scale	
Exhaust water header pressure (upstream)	Pressure indicator	0 - 1800 psig	± 1/2% full scale	
Exhaust water header pressure (downstream)	Pressure indicator	0 - 1800 psig	±1/2% full scale	
Changing water header pressure	Pressure indicator	0 - 1800 psig	± 2% full scale	1510 psig
Drive water pump suction pressure	Pressure switch	0 - 30 in. Hg	± 5% full scale	25 in. Hg abs
Drive water flowrate	Flow indicator	0 - 58 gal/min	± 2% full scale	
Cooling water header flowrate	Flow indicator	0 - 80 gal/min	± 2% full scale	
Stabilizing flowrate	Flow indicator	1 - 8 gal/min	± 5% full scale	
CRD temperature	Temperature switch	0 - 400°F		250°F
Control rod position (normal range)	Reed switches	Full-in to full-out every 3 in.	± 1 1/2 in	
CRD overtravel (withdraw direction)	Reed switches	7/8 in. beyond full insert position	± 1 1/2 in	7/8 in. beyond full insert position
Insert bus time energized (for rod insertion)	Timer			2.9 s

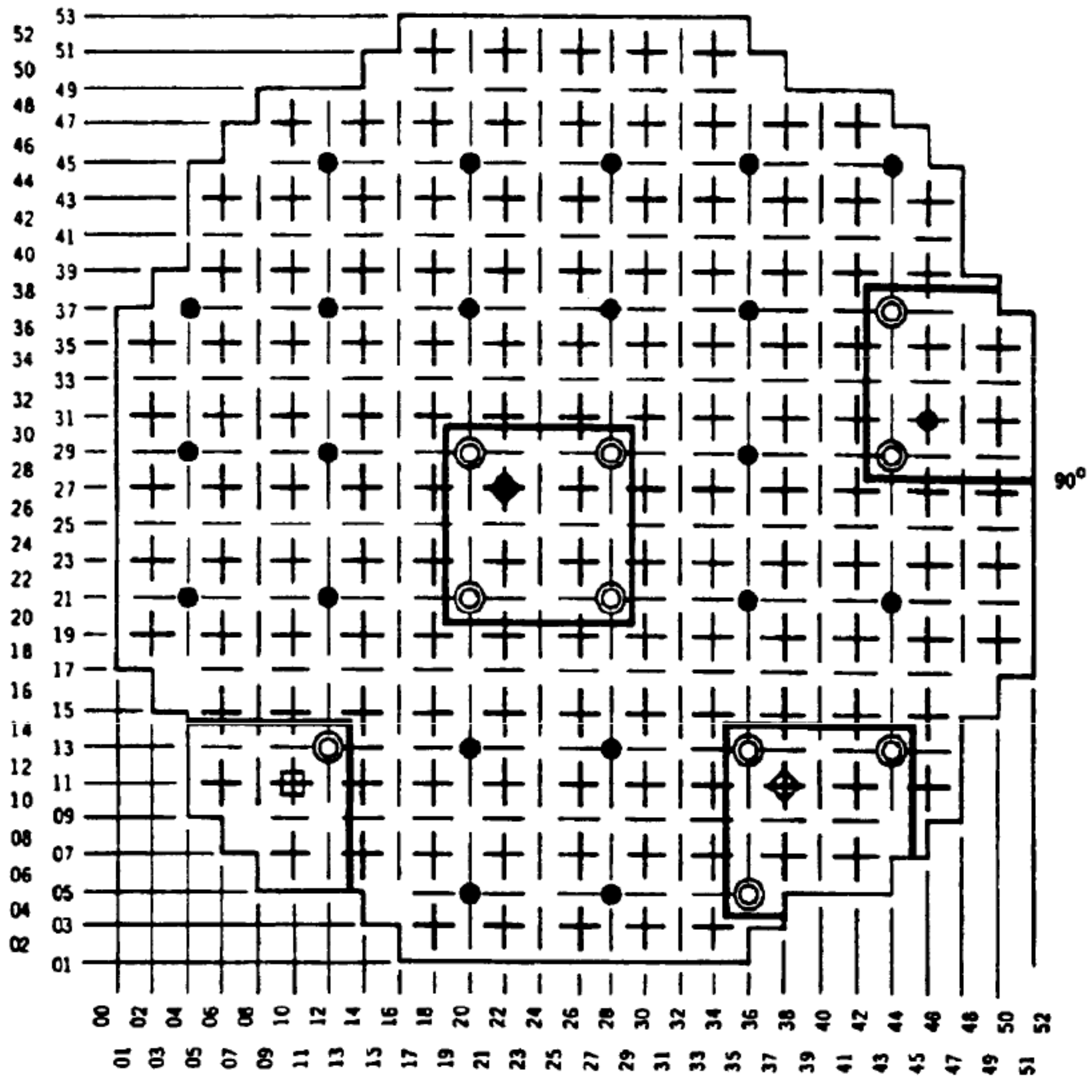
TABLE 7.7-1 (SHEET 2 OF 2)

Measured Variable	Instrument Type	Normal Range	Accuracy	Trip Setting
Insert bus time energized for rod withdrawal)	Timer			0.65 s
Withdraw bus time energized (for rod withdrawal)	Timer			1.5 s
Settle bus time energized (for rod insertion)	Timer			4.5 s
Settle bus time energized (for rod withdrawal)	Timer			6.0 s
Rod block - scram discharge volume high water level	Level switch		± 0.5 in.	(a)
Rod block - NMS trip channels	Neutron Monitoring System (See subsection 7.6.2.)			
Rod block - RWM	Process Computer System (See subsection 7.6.8.)			

a. Allowable values are specified in HNP-2 Technical Requirements Manual. See HNP-2 Instrument Setpoint Index for actual setpoints.

CORE TOP VIEW

0°



LPRM INPUT UPON ROD SELECTION

TYPICAL ROD YIELDING FOUR STRING INPUT

TYPICAL ROD YIELDING THREE STRING INPUT

TYPICAL ROD YIELDING TWO STRING INPUT

TYPICAL ROD YIELDING ONE STRING INPUT

THE LPRMs AND RODS WITHIN THE HEAVILY MARKED LINES AROUND THE SELECTED ROD ARE THOSE PRESENTED ON THE FOUR-ROD DISPLAY

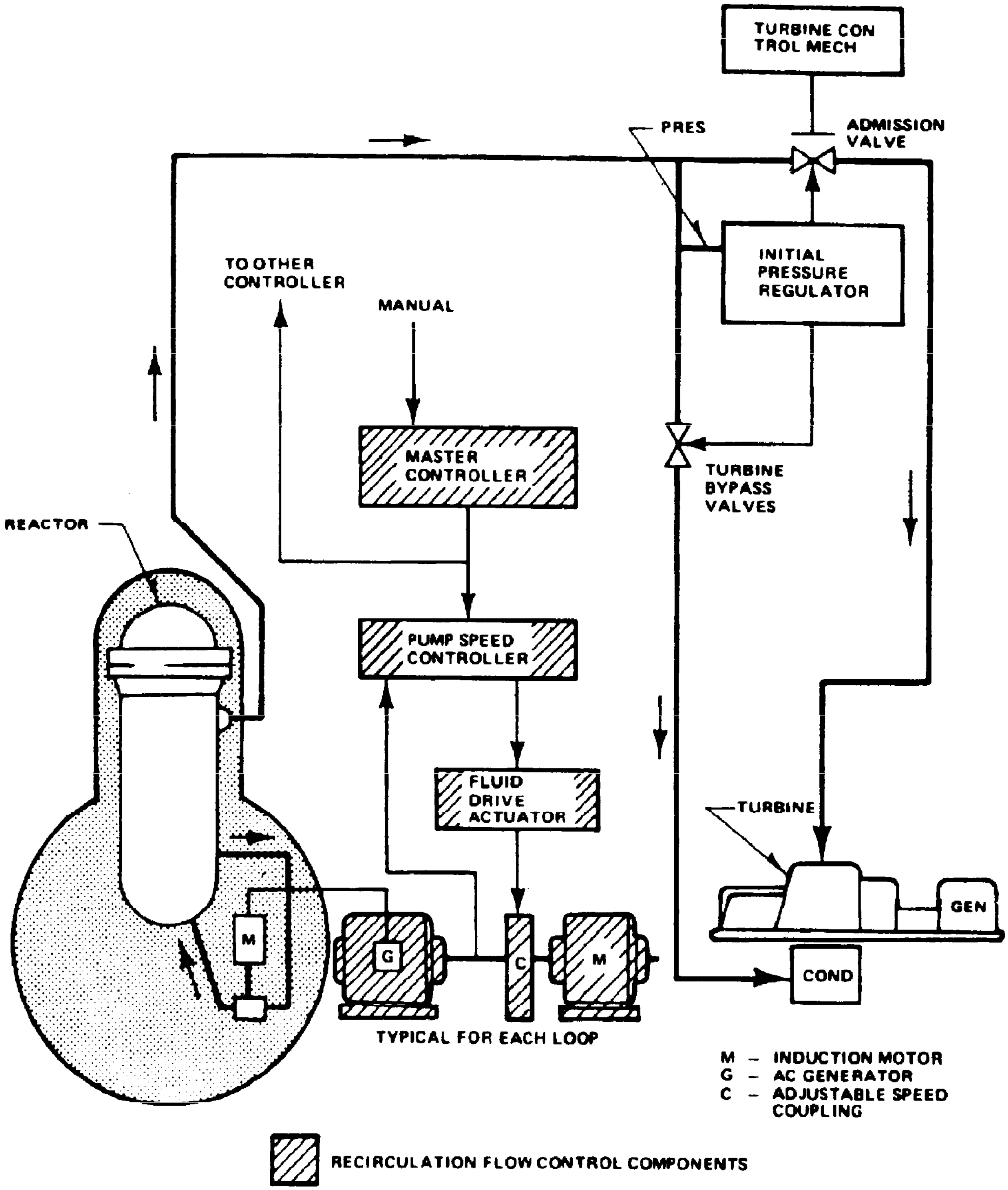
ACAD 2070701

REV 19 7/01

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

INPUT SIGNALS TO FOUR-ROD DISPLAY

FIGURE 7.7-1



ACAD 2070702

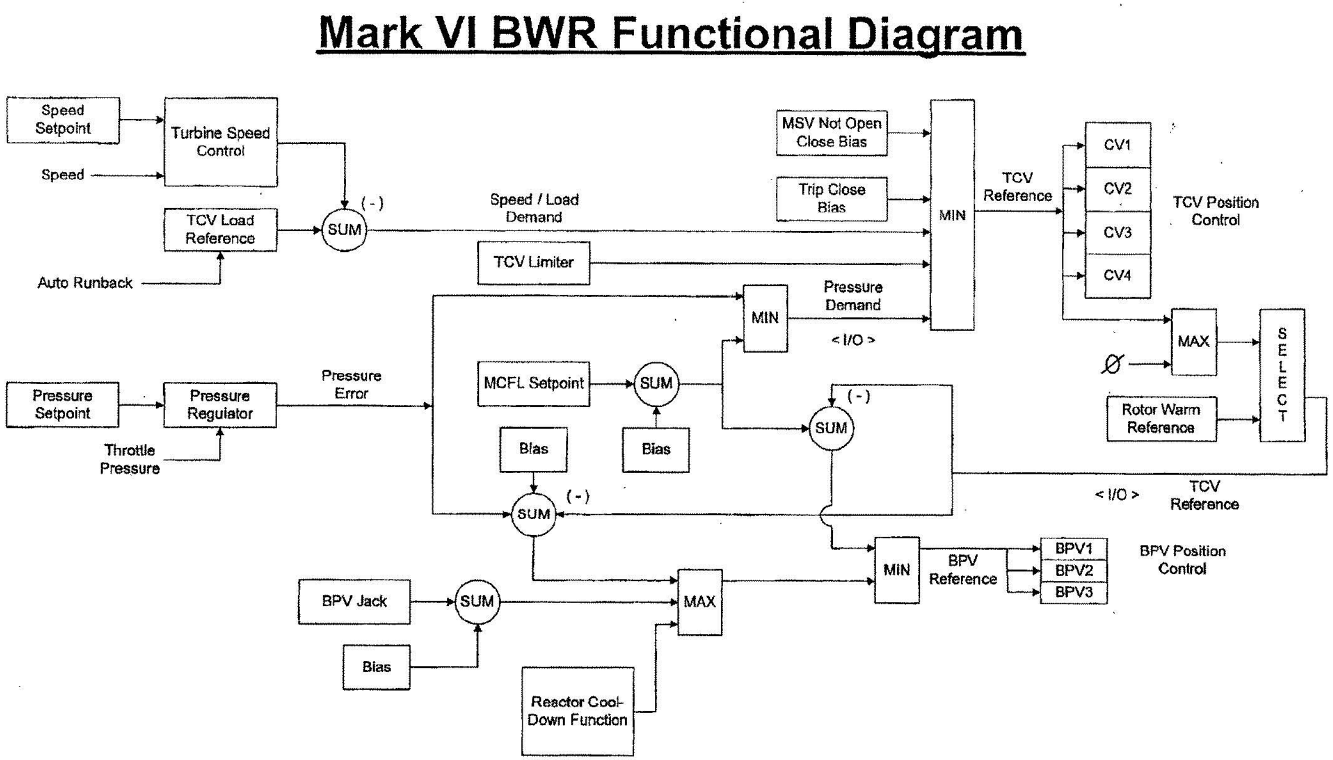
REV 27 10/09

SOUTHERN COMPANY

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

RRS FLOW CONTROL ILLUSTRATION

FIGURE 7.7-2



REV 27 10/09

SOUTHERN COMPANY

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

SIMPLIFIED DIAGRAM OF TURBINE PRESSURE AND SPEED-LOAD CONTROL SYSTEM

FIGURE 7.7-3

7.8 ANALOG TRANSMITTER TRIP SYSTEM (ATTS)

7.8.1 DESIGN BASES

The ATTS was installed to upgrade instrumentation in the reactor protection system (RPS), primary containment isolation system (PCIS), emergency core cooling system (ECCS), and reactor core isolation cooling (RCIC) system. The components replaced as part of the ATTS system function as an integral part of the system in which they are installed and as such, meet all the design bases of that system.

7.8.1.1 Design Features

The ATTS design includes the below listed design features:

A. Each component of the ATTS shall be environmentally qualified for its intended service per the requirements of section 3.11.

B. All components of the ATTS shall be Seismic Category I and qualified per supplement 3.7A and paragraph 3.10.2.2.3.

C. The ATTS shall reduce the time the RPS logic must be in a half-scram condition due to functional testing or calibrating of a safety trip.

D. The calibration frequency of a primary sensor shall be once per operating cycle.

E. The ATTS shall provide continuous monitoring of sensor loop parameters. To detect primary sensor element drift, a channel check is performed once per operator shift.

F. The ATTS shall be designed to minimize the time required to perform functional tests or to calibrate the trip setpoint.

G. The ATTS shall be designed to minimize the probability of instrument-valving errors and instrument testing-related scrams.

7.8.2 SYSTEM DESCRIPTION

7.8.2.1 General

The ATTS is an all solid-state electronic trip system designed to provide stable and accurate monitoring of process parameters.

The system consists of primary sensors, master trip assemblies, slave trip assemblies, calibration units, card file assemblies, and other accessories.

The process parameters monitored by the ATTS are listed in table 7.8-1.

7.8.2.2 Equipment Description and Design

7.8.2.2.1 Process Sensors

Process parameters are continuously sensed by pressure transmitters, differential pressure transmitters and resistance temperature detectors (RTDs) which are mounted locally or on instrument racks in the reactor building. Analog signals proportional to the actual process conditions are provided by the process sensors via cables routed to the trip units located in the main control room (MCR).

7.8.2.2.2 Master Trip Units

Each master trip unit is a plug-in, printed-wire assembly designed to accept a 4 to 20-mA signal from the remote transmitter or the input of a three-wire 100-ohm platinum RTD. Each trip unit contains the circuitry necessary to condition these inputs and provide the desired switching functions and analog output signals to slave trip units and other instruments external to the ATTS. The master trip units provide output to energize or deenergize trip relays at any point within the 4- to 20-mA or resistance input signal range. An electrical elementary drawing depicting a typical application is shown in figure 7.8-1. Each master trip unit also contains an isolated panel meter that displays the value of the measured parameters which can be scaled in the units of the process variable. The meter is not considered an integral part of the safety system channel.

Test jacks are provided on each master trip unit face for measurement of actual parameter values. A two-position logic invert switch internal to each trip unit allows for the selection of either a high trip or low trip, thereby allowing the trip relays to be either energized or deenergized during normal operation. The system requirements dictate the position of the logic invert switch.

7.8.2.2.3 Slave Trip Units

The slave trip units are used in conjunction with master trip units when it is desirable to have different setpoints from a common sensor. Each slave obtains its input from an analog output signal of a master trip unit. Up to seven slaves can be driven by a single master trip unit, thus permitting eight different setpoints from a single measured parameter. Unlike the master, there is no direct connection of the slave to a sensor, nor are any analog signals generated by the slave. However, each slave has its own output logic switching function for either high or low trip which is independent of its master or other parallel slaves.

7.8.2.2.4 Differential Voltage Trip Units

The differential voltage trip units receive input from two master trip units. These differential voltage trip units are used for the differential temperature trips in the steam leak detection system; and, similar to a master trip unit, it has a front panel meter to show the value of the measured parameter. The output configuration for a differential voltage trip unit is the same as for a master trip unit.

7.8.2.2.5 Trip Relays

Each master, slave, or differential voltage trip unit is capable of supplying trip relay loads up to 1 A at nominal 25 V-dc. Contacts from these relays provide the necessary logic function for the process variable input. The trip relays provide input to only one division and are not considered an interdivisional isolation device. The trip relays used have four single-pole-double-throw contacts; therefore, the relays will provide any contact logic function that the system requires. Also, the relays are used to provide Class 1E to non-Class 1E isolation for input to the annunciators.

7.8.2.3 Power Sources

Power sources to the ATTS cabinets are supplied from the following buses:

A. The ATTS RPS cabinets are supplied with 120-V-ac power from the RPS buses which are powered by RPS motor generator sets.

B. The ATTS ECCS cabinets are supplied with 125-V-dc power from the dc buses 2A and 2B which are backed up by the plant service battery system.

Each ATTS cabinet is supplied with two voltage converters which convert 120 V-ac or 125 V-dc to 25 V-dc. The converted voltage has the following design features to assure a highly reliable power supply:

A. Two power sources from different buses listed above feed each ATTS cabinet.

B. Each power source has its own voltage converter in each cabinet.

7.8.2.4 Initiating Circuits

The ATTS senses essential process parameters and generates trip signals which are input to initiating circuits for RPS, PCIS, ECCS, RCIC system, alternate rod insertion (ARI) system, and low-low set (LLS) relief logic system. The initiating circuits for which ATTS provides trip signals are discussed in sections 7.2, 7.3.1, 7.3.2, 7.4.1, 7.4.4, and paragraph 4.2.3.2.2.4.

7.8.2.5 Logic and Sequencing

The ATTS does not perform any logic or sequencing internal to itself but does provide input for the logic and sequencing of the RPS, PCIS, ECCS, RCIC system, ARI system, and LLS relief logic system as discussed in sections 7.2, 7.3.1, 7.3.2, 7.4.1, 7.4.4, and paragraph 4.2.3.2.2.4, respectively.

7.8.2.6 Bypasses, Interlocks, and Alarms

Each master, slave, and differential voltage trip unit has a gross-failure and trip light-emitting diode (LED). The trip LED is illuminated when the setpoint is exceeded, and the gross-failure LED is illuminated when one or more of the following conditions exist:

A. Gross Failure Low

The most important function of the low gross-failure alarm is to sense an open sensor loop; however, some failures within the sensor or trip unit are detected by the low gross-failure detection circuit. After the low gross failure has been cleared, the alarm must be manually reset.

B. Gross Failure High

The primary function of the high sensor is to annunciate a short circuit of the sensor or its loop. Some component failures within the sensor or trip unit are also detected by the high gross-failure detection circuit. After the high gross-failure has been cleared, the alarm must be manually reset.

C. Card in Calibration

When any trip unit is selected by the calibration unit and placed in the calibrate mode, the calibrate command signal, which switches the input current from the sensor to the calibration unit, is transmitted from the calibrator to the trip unit, thereby turning on the gross-failure LED. However, unlike the other gross-failure circuitry, the calibrate command signal does not latch the gross-failure output. Therefore, when the card is taken out of the calibration mode, the gross-failure output automatically resets and the annunciator may be immediately cleared.

The trip cards, arranged within a common-card file, are connected to form a series loop between the positive 25-V supply voltage and a normally energized relay coil. Removal of any trip unit within the card file will break the current loop and cause the relay to drop out and annunciate via normally closed contacts wired from the relay to an annunciator in the cabinet.

7.8.2.7 Redundancy, Diversity, and Separation

The redundancy, diversity, and separation requirements for the ATTS are consistent with those of the RPS, ECCS, PCIS, RCIC system, ARI system, and LLS relief logic system, which are discussed in sections 7.2, 7.3.1, 7.3.2, 7.4.1, 7.4.4, and paragraph 4.2.3.2.2.4, respectively.

7.8.2.8 Actuated Devices

The ATTS does not directly actuate any devices. Devices are actuated via the RPS, PCIS, ECCS, RCIC system, ARI system, and LLS relief logic system.

7.8.2.9 Testability

The ATTS is not testable as a system since it is an assemblage of independent instrument loops which must be individually tested.

Each master trip unit provides continuous readout of the transmitter control current via the meter located on the front panel, which is calibrated in terms of the process variable. In addition, an output jack provides a 1- to 5-V-dc signal proportional to the process range being monitored. The operator is able to cross-check the transmitter output currents by comparison with transmitters measuring the same variable and, therefore, can determine whether one of the transmitters is malfunctioning.

Each card file is supplied with a calibration unit whose function is to furnish the means by which an in-place calibration check of the master and slave trip units can be performed. The calibrator contains both a stable and a transient current source. The stable current is for verification of the calibration point of any given channel. The transient current source is used to provide a step current input into a selected channel, such that the response time of that channel can be determined from the trip unit input to any point downstream in the logic, including the final element.

7.8.2.10 Environmental Considerations

The ATTS trip units, relays, voltage converters, and miscellaneous cabinet equipment are located in the MCR and are subjected to only a mild environment.

The transmitters and RTDs, which are located in the reactor building, are qualified for the environments associated with any high-energy line break for the areas in which they are located.

Paragraph 3.11.3.1.B.1 describes the ATTS qualification test results.

7.8.2.11 Operational Considerations

The ATTS is required and designed to operate during normal plant operation and during and after a design basis accident to the extent required by the specific systems to which the ATTS provides input signals.

7.8.3 ANALYSIS

7.8.3.1 Conformance to General Functional Requirements[a]

The ATTS affects those systems to which it provides input on a sensor level but not a logic level. The ATTS instrumentation meets the general functional requirements of the specific systems to which it provides input.

7.8.3.2 Conformance to Specific Regulatory Requirements

The ATTS hardware conforms to the standards and regulations listed in reference 1.

The ATTS installation conforms to the standards and regulations required by the specific systems to which it provides input signals. The standards and regulations are listed in sections 7.2, 7.3.1, 7.3.2, 7.4.1, and 7.4.4.

The trip setpoints/allowable values were developed using the criteria of Regulatory Guide 1.105.

a. The minimum number of operable channels, response time, etc.

REFERENCES

1. "Analog Trip System for Engineered Safeguard Sensor Trip Inputs - Edwin I. Hatch Nuclear Plant Units 1 and 2," NEDE-22154-1, General Electric Company, July 1983.

TABLE 7.8-1 (SHEET 1 OF 7)

ATTS INSTRUMENT LOOPS

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
RPV steam dome pressure high	2B21-PT-N078 A,B,C,D	2B21-PIS-N678 A,B,C,D	RPS	Scram signal	A,B-2H21-P404C,D C,D-2H21-P405C,D	H-26001
RPV water level 3	2B21-LT-N080 A,B,C,D	2B21-LIS-N680 A,B,C,D	RPS	Scram signal, PCIS (Groups 2, 6, 7, 10, 11 & 12)	A,B-2H21-P404C,D C,D-2H21-P405C,D	H-26001
RPV water level 1	2B21-LT-N081 A,B,C,D	2B21-LIS-N681 A,B,C,D	RPS	PCIS (group 1)	A,B-2H21-P404C,D C,D-2H21-P405C,D	H-26001
RPV water level 2	2B21-LT-N081 A,B,C,D	2B21-LS-N682 A,B,C,D[(a)]	RPS	PCIS (group 5 and secondary containment)	A,B-2H21-P404C,D C,D-2H21-P405C,D	H-26001
Reactor shroud water level (level O)	2B21-LT-N085 A,B	2B21-LIS-N685 A,B	ECCS	Containment spray permissive	A-2H21-P409 B-2H21-P410	H-26001
Main steam line A high flow	2B21-dPT-N086 A,B,C,D	2B21-dPIS-N686 A,B,C,D	RPS	PCIS (Group 1)[(b)]	A,B-2H21-P415A,B C,D-2H21-P425A,B	H-26000
Main steam line B high flow	2B21-dPT-N087 A,B,C,D	2B21-dPIS-N687 A,B,C,D	RPS	PCIS (Group 1)[(b)]	A,B-2H21-P415A,B C,D-2H21-P425A,B	H-26000
Main steam line C high flow	2B21-dPT-N088 A,B,C,D	2B21-dPIS-N688 A,B,C,D	RPS	PCIS (Group 1)[(b)]	A,B-2H21-P415A,B C,D-2H21-P425A,B	H-26000
Main steam line D high flow	2B21-dPT-N089 A,B,C,D	2B21-dPIS-N689 A,B,C,D	RPS	PCIS (Group 1)[(b)]	A,B-2H21-P415A,B C,D-2H21-P425A,B	H-26000
RPV pressure low	2B21-PT-N090 A,D	2B21-PIS-N690 A,D	ECCS	CS,LPCI	A-2H21-P404A D-2H21-P405A	H-26001
RPV pressure low	2B21-PT-N090 E,F	2B21-PIS-N690 E,F	ECCS	LPCI	E-2H21-P404A F-2H21-P405A	H-26001

TABLE 7.8-1 (SHEET 2 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
RPV pressure low	2B21-PT-N090 B,C	2B21-PIS-N690 B,C	ECCS	CS, LPCI	B-2H21-P410 C-2H21-P409	H-26001
RPV pressure low	2B21-PT-N090 B,C	2B21-PS-N641 B,C[(a)]	ECCS	LPCI	B-2H21-P410 C-2H21-P409	H-26001
RPV water level 1	2B21-LT-N091 A,B,C,D	2B21-LIS-N691 A,B,C,D	ECCS	CS,LPCI, ADS, diesel[(b)]	A,C-2H21-P404A B,D-2H21-P405A	H-26001
RPV water level 2	2B21-LT-N091 A,B,C,D	2B21-LS-N692 A,B,C,D[(a)]	ECCS	HPCI, RCIC	A,C-2H21-P404A B,D-2H21-P405A	H-26001
RPV water level low	2B21-LT-N091 A,B,C,D	2B21-LS-N694 A,B,C,D[(a)]	ECCS	ATWS-RPT	A,C-2H21-P404A B,D-2H21-P405A	H-26001
RPV water level 8	2B21-LT-N093 A,B	2B21-LIS-N693 A,B	ECCS	HPCI, RCIC	Local	H-26001
RPV water level 3	2B21-LT-N095 A,B	2B21-LIS-N695 A,B	ECCS	ADS	A-2H21-P404B B-2H21-P405B	H-26001
RPV water level 8	2B21-LT-N095 A,B	2B21-LS-N693 C,D[(a)]	ECCS	HPCI, RCIC	A-2H21-P404B B-2H21-P405B	H-26001
RPV pressure LLS arming permissive	2B21-PT-N120 A,B,C,D	2B21-PIS-N620 A,B,C,D	ECCS	LLS	A,C-2H21-P404A,B B,D-2H21-P405A,B	H-26001
RPV pressure LLS control	2B21-PT-N120 A,B,C,D	2B21-PS-N621 A,B,C,D[(a)]	ECCS	LLS	A,C-2H21-P404A,B B,D-2H21-P405A,B	H-26001
RPV pressure high	2B21-PT-N120 A,B	2B21-PS-N642 A,B[(a)]	ECCS	ATWS-ARI ATWS-RPT	A-2H21-P404A B-2H21-P405A	H-26001
RPV LLS control	2B21-PT-N122 C,D	2B21-PIS-N622 C,D	ECCS	LLS	C-2H21-P404B D-2H21-P405B	H-26001

TABLE 7.8-1 (SHEET 3 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
RPV pressure high	2B21-PT-N122 A,B	2B21-PIS-N643 A,B	ECCS	ATWS-ARI ATWS-RPT	A-2H21-P404A B-2H21-P405A	H-26001
RPV LLS control	2B21-PT-N122 A,B	2B21-PS-N622 A,B[(a)]	ECCS	LLS	A-2H21-P404A B-2H21-P405A	H-26001
Steam tunnel high temperature	2B21-TE-N123 A,B,C,D	2B21-TIS-N623 A,B,C,D	RPS	PCIS (Group 1)	Local	H-26000
Steam tunnel high temperature	2B21-TE-N124 A,B,C,D	2B21-TIS-N624 A,B,C,D	RPS	PCIS (Group 1)	Local	H-26000
Steam tunnel high temperature	2B21-TE-N125 A,B,C,D	2B21-TIS-N625 A,B,C,D	RPS	PCIS (Group 1)	Local	H-26000
Steam tunnel high temperature	2B21-TE-N126 A,B,C,D	2B21-TIS-N626 A,B,C,D	RPS	PCIS (Group 1)	Local	H-26000
ECCS div I SRV actuation	2B21-PT-N127 A	2B21-PIS-N697 A	ECCS	SRV logic	A-2H21-P404B	H-26000 H-26001
ECCS div I SRV actuation	2B21-PT-N127 A	2B21-PS-N697 G,L[(a)]	ECCS	SRV logic	A-2H21-P404B	H-26000 H-26001
ECCS div II SRV actuation	2B21-PT-N127 B	2B21-PIS-N697 B	ECCS	SRV logic	B-2H21-P405B	H-26000 H-26001
ECCS div II SRV actuation	2B21-PT-N127 B	2B21-PS-N697 K,H[(a)]	ECCS	SRV logic	B-2H21-P405B	H-26000 H-26001
ECCS div I SRV actuation	2B21-PT-N127 C	2B21-PIS-N697 C	ECCS	SRV logic	C-2H21-P404C	H-26000 H-26001
ECCS div I SRV actuation	2B21-PT-N127 C	2B21-PS-N697 F,E[(a)]	ECCS	SRV logic	C-2H21-P404C	H-26000 H-26001

TABLE 7.8-1 (SHEET 4 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
ECCS div II SRV actuation	2B21-PT-N127 D	2B21-PIS-N697 D	ECCS	SRV logic	D-2H21-P405D	H-26000 H-26001
ECCS div II SRV actuation	2B21-PT-N127 D	2B21-PS-N697 M,J[(a)]	ECCS	SRV logic	D-2H21-P405D	H-26000 H-26001
SRV initiation LLS arming logic permissive	2B21-PS-N302 A-H, K,L,M	NA	ECCS	LLS	Local	H-26000
SRV initiation LLS arming logic permissive	2B21-PS-N301 A-H, K,L,M	NA	ECCS	LLS	Local	H-26000
RPV steam dome low pressure permissive	2B31-PT-N079 A,D	2B31-PIS-N679 A,D	RPS	PCIS (Group 6)	A-2H21-P404E D-2H21-P405E	H-26001
Drywell high pressure	2C71-PT-N050 A,B,C,D	2C71-PIS-N650 A,B,C,D	RPS	Scram signal, PCIS (Groups 2, 7, 10, 11, 12 & secondary containment)	Local	
RHR pump discharge high pressure	2E11-PT-N055 A,B,C,D	2E11-PIS-N655 A,B,C,D	ECCS	ADS	A,C-2H21-P418B B,D-2H21-P421B	H-26014 H-26015
RHR pump discharge high pressure	2E11-PT-N056 A,B,C,D	2E11-PIS-N656 A,B,C,D	ECCS	ADS	A,C-2H21-P418B B,D-2H21-P421B	H-26014 H-26015
RHR pump flow low	2E11-dPT-N082 A,B	2E11-dPIS-N682 A,B	ECCS	LPCI	A-2H21-P418A B-2H21-P421A	H-26014 H-26015
Drywell high pressure	2E11-PT-N094 A,B,C,D	2E11-PIS-N694 A,B,C,D	ECCS	PCIS (Groups 8 & 9), HPCI, CS[(b)] LPCI, ADS, diesel	Local	H-26014 H-26015
CS pump discharge low flow	2E21-dPT-N051 A,B	2E21-dPIS-N651 A,B	ECCS	CS	A-2H21-P401 B-2H21-P419	H-26018

TABLE 7.8-1 (SHEET 5 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
CS pump discharge high pressure	2E21-PT-N052 A,B	2E21-PIS-N652 A,B	ECCS	ADS	A-2H21-P401 B-2H21-P419	H-26018
CS pump discharge high pressure	2E21-PT-N055 A,B	2E21-PIS-N655 A,B	ECCS	ADS	A-2H21-P401 B-2H21-P419	H-26018
HPCI pump high pressure	2E41-PT-N050	2E41-PIS-N650	ECCS	HPCI	2H21-P414B	H-26020
HPCI pump discharge high flow	2E41-dPT-N051	2E41-dPIS-N651	ECCS	HPCI	2H21-P414A	H-26020
HPCI pump suction low pressure	2E41-PT-N053	2E41-PIS-N653	ECCS	HPCI	2H21-P414B	H-26021
HPCI pump suction low pressure alarm	2E41-PT-N053	2E41-PS-N654[(a)]	ECCS	HPCI	2H21-P414B	H-26021
HPCI turbine exhaust diaphragm high pressure	2E41-PT-N055 A,B,C,D	2E41-PIS-N655 A,B,C,D	ECCS	PCIS (Group 3)	A,C-2H21-P434 B,D-2H21-P414A	H-26021
HPCI turbine exhaust high pressure	2E41-PT-N056 B,D	2E41-PIS-N656 B,D	ECCS	HPCI	2H21-P414B	H-26021
HPCI steam line high flow	2E41-dPT-N057 A,B	2E41-dPIS-N657 A,B	ECCS	PCIS (Group 3)	A-2H21-P016 B-2H21-P036	H-26020
HPCI steam line high differential pressure (-)	2E41-dPT-N057 A,B	2E41-dPS-N660 A,B	ECCS	PCIS (Group 3)	A-2H21-P016 B-2H21-P036	H-26020
HPCI steam supply low pressure	2E41-PT-N058 A,B,C,D	2E41-PIS-N658 A,B,C,D	ECCS	PCIS (Group 3)	A,C-2H21-P016 B,D-2H21-P036	H-26020
HPCI torus high water level	2E41-LT-N062 B,D	2E41-LIS-N662 B,D	ECCS	HPCI	Local	H-26020
HPCI equipment high ambient temperature	2E41-TE-N070 A,B	2E41-TIS-N670 A,B	ECCS	PCIS (Group 3)	Local	H-26021

TABLE 7.8-1 (SHEET 6 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
HPCI pipe room high ambient temperature	2E41-TE-N071 A,B	2E41-TIS-N671 A,B	ECCS	PCIS (Group 3)	Local	H-26021
RCIC pump discharge high pressure	2E51-PT-N050	2E51-PIS-N650	ECCS	RCIC	2H21-P417B	H-26023
RCIC pump discharge high flow	2E51-dPT-N051	2E51-dPIS-N651	ECCS	RCIC	2H21-P417A	H-26023
RCIC turbine exhaust high pressure	2E51-PT-N056 A,C	2E51-PIS-N656 A,C	ECCS	RCIC	2H21-P417B	H-26024
RCIC steam line high flow	2E51-dPT-N057 A,B	2E51-dPIS-N657 A,B	ECCS	PCIS (Group 4)	A-2H21-P435 B-2H21-P038	H-26023
RCIC steam line high differential pressure (-)	2E51-dPT-N057 A,B	2E51-dPS-N660[(a)] A,B	ECCS	PCIS (Group 4)	A-2H21-P435 B-2H21-P038	H-26023
RCIC steam supply low pressure	2E51-PT-N058 A,B,C,D	2E51-PIS-N658 A,B,C,D	ECCS	PCIS (Group 4)	A,C-2H21-P435 B,D-2H21-P038	H-26023
RCIC equipment high ambient temperature	2E51-TE-N061 A,B	2E51-TIS-N661 A,B	ECCS	PCIS (Group 4)	Local	H-26023
Torus ambient temperature (no trip)	2E51-TE-N063 A,B,C,D	2E51-TIS-N663[(c)] A,B,C,D	ECCS	PCIS (Groups 3 & 4)	Local	H-26024
Torus ambient temperature (no trip)	2E51-TE-N064 A,B,C,D	2E51-TIS-N664[(c)] A,B,C,D	ECCS	PCIS (Groups 3 & 4)	Local	H-26024
Torus differential temperature (high)	NA	2E51-dTIS-N665[(d)] A,B,C,D	ECCS	PCIS (Groups 3 & 4)	NA	H-26024
Torus high ambient temperature	2E51-TE-N066 A,B,C,D	2E51-TIS-N666 A,B,C,D	ECCS	PCIS (Groups 3 & 4)	Local	H-26024
RCIC pump suction low pressure	2E51-PT-N083	2E51-PIS-N683	ECCS	RCIC	2H21-P417B	H-26024

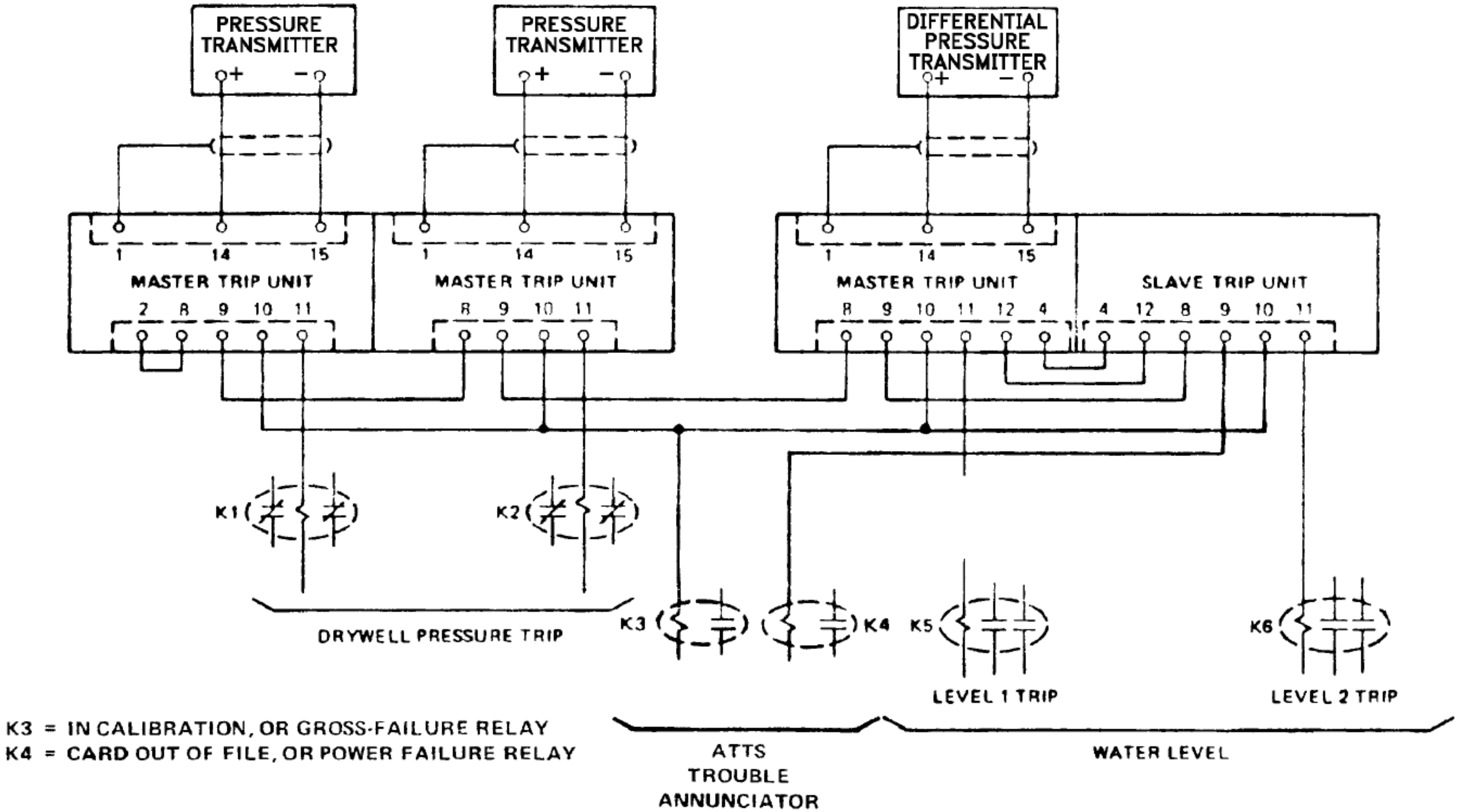
TABLE 7.8-1 (SHEET 7 OF 7)

Variable Name	Primary Sensor MPL No.	Trip Unit MPL No.	Engineering Safeguard Division	Engineering Safeguard Function	Associated Rack (Sensor)	Referenced Drawing
RCIC pump suction low pressure (alarm)	2E51-PT-N083	2E51-PS-N684[a]	ECCS	RCIC	2H21-P417B	H-26024
RCIC turbine exhaust diaphragm high pressure	2E51-PT-N085 A,B,C,D	2E51-PIS-N685 A,B,C,D	ECCS	PCIS (Group 4)	A,C-2H21-P417A B,D-2H22-P437	H-26024
RWC room temperature inlet (no trip)	2G31-TE-N061 A,D,E,H,J,M	2G31-TIS-N661[e] A,D,E,H,J,M	RPS	PCIS (Group 5)	Local	H-26036
RWC room temperature outlet high	2G31-TE-N062 A,D,E,H,J,M	2G31-TIS-N662 A,D,E,H,J,M	RPS	PCIS (Group 5)	Local	H-26036
RWC area ventilation differential temperature high	NA	2G31-dTIS-N663[f] A,D,E,H,J,M	RPS	PCIS (Group 5)	NA	H-26036

LEGEND

ADS - automatic depressurization system
CS - core spray
HPCI - high-pressure coolant injection
LPCI - low-pressure coolant injection
RHR - residual heat removal
RPV - reactor pressure vessel
RWC - reactor water cleanup

a. This is a slave trip unit to the first master trip unit listed above it.
b. Actuates MCR vent system in pressurization mode.
c. No tripping function serves as input to ΔT trip unit 2E51-dTIS-N665A,B,C,D.
d. Input to trip card supplied by 2E51-TIS-N663A,B,C,D and N664A,B,C,D.
e. No tripping function serves as input to ΔT trip unit 2G31-dTIS-N665A,D,E,H,J,M.
f. Input to trip unit supplied by 2G31-TIS-N661A,D,E,H,J,M and N662A,D,E,H,J,M.



ACAD 2070801

REV 19 7/01

SOUTHERN COMPANY
Energy to Serve Your World®

SOUTHERN NUCLEAR OPERATING COMPANY
EDWIN I. HATCH NUCLEAR PLANT
UNIT 2

TYPICAL TRIP UNIT/CALIBRATION SYSTEM ELEMENTARY

FIGURE 7.8-1

7.9 SAFETY PARAMETER DISPLAY SYSTEM/EMERGENCY RESPONSE DATA SYSTEM/NRC EMERGENCY RESPONSE DATA SYSTEM (HNP-1 AND HNP-2)

7.9.1 DESIGN CONSIDERATIONS

The purpose of the Edwin I. Hatch Nuclear Plant (HNP) safety parameter display system (SPDS) and emergency response data system (ERDS) is to aid the plant operators in rapidly assessing the plant safety status during normal, anticipated operational occurrences, and accident conditions. The systems were designed to meet the intent of pertinent Nuclear Regulatory Commission (NRC) requirements and guidance contained in NUREG-0737, Supplement 1 (Generic Letter 82-33), NUREG-0696, and Regulatory Issues Summary 2009-13, Emergency Response Data System Upgrade From Modem to Virtual Private Network Appliance.

The systems provide computer-generated information to the main control room (MCR), technical support center (TSC), and the emergency operations facility (EOF) for effective management of an accident.

The functions of the SPDS and the ERDS are accomplished by the same computer-based equipment. Therefore, the system will be designated collectively as SPDS/ERDS.

7.9.2 SYSTEM DESCRIPTION

The SPDS/ERDS configuration with inputs and interfaces is shown on HNP-1 drawing no. H-16339 and HNP-2 drawing no. H-26191. Information from plant process instrumentation provides input to the SPDS/ERDS. Those signals originating in Class 1E instrumentation loops are isolated from the safety grade portion of the system using the appropriate Class 1E isolation devices.

A majority of the input signals are obtained directly from the MCR instrument circuits. All input signals are multiplexed by distributed hybrid control systems that connect to the SPDS Ethernet local area network (LAN). Class 1E analog signals are isolated from the hybrid control system analog input devices, while various Class 1E digital signal loops are isolated either from the hybrid control system digital input devices or at the output of the hybrid control system digital input devices. Class1E analog and digital signals are isolated from the SPDS computer using appropriate Class 1E isolation devices.

The parameters selected to be included in the SPDS were compiled using such documents as NUREG-0696, Regulatory Guide 1.97, the plant Technical Specifications, the BWR Owners Group (BWROG) SPDS Functional Specification, and the HNP Emergency Operating Procedures. The intent of the parameter selection process was to provide the operator with a set of verified parameters from which he can rapidly assess the safety status of the plant during all normal and abnormal operating conditions and to assist him in assessing whether abnormal conditions warrant corrective action to avert a degraded core.

The SPDS system is designed such that only a minimum number of parameters required to assess the safety status of the plant are displayed on the primary display. These displayed parameters are validated by computer calculation and/or comparison to related instruments. The operator is apprised of an invalid value by a color change and any potentially unsafe condition by a different color change on the display screen. Extensive use of color and human factors engineering principles assures that the system is easy to use and can convey plant status information rapidly and reliably.

The SPDS is also used to record process data for plant performance optimization and for process computer alarm, post-trip, and scram logging functions for selected significant status changes and contact actuated input data.

7.9.2.1 SPDS/ERDS Hardware

The SPDS/ERDS hardware is located in the control building (including MCR), service building (including TSC), diesel-generator building, and turbine building.

There are four SPDS/ERDS server computers (PCs): one dedicated for HNP-1 data acquisition and processing, one dedicated for HNP-2 data acquisition and processing, and two backup server computers, one each for HNP-1 and HNP-2 operation. A management server is provided to monitor HNP-1 and HNP-2 SPDS/ERDS system health. All server PCs as well as the SPDS LAN switches are located in the plant process computer room.

SPDS client computers (PCs) are positioned in various locations in the central MCR operator area. Panel mounted PCs used as digital displays are located on the reactor control console. Each PC is connected to the SPDS LAN and displays the data obtained from the hybrid control systems.

Non-1E digital hybrid control system input panels are also located in the diesel building; the turbine building, el 130 ft; and the control building, el 112 ft. These panels collect input status information at these locations and communicate it to the SPDS server computer.

Alarm, post-trip, and scram event data recorded by the SPDS can be printed on a LAN printer located in the plant process computer room.

7.9.2.2 Technical Support Center Data System

Two SPDS/ERDS client computers (PCs) are located in the TSC. Each PC obtains data from the SPDS/ERDS via data connections to the SPDS local area network (SPDS LAN). Each TSC PC can display either HNP-1 or HNP-2 SPDS/ERDS data, but not both simultaneously, using display software installed on each PC.

The TSC is further described in sections 9.3, 9.4, and 12.3.

7.9.2.3 Emergency Operations Facility Data System

Two SPDS/ERDS client computers (PCs) are located in the EOF. Each PC obtains data from the SPDS/ERDS via data connections to the SPDS LAN. Each EOF PC can display either HNP-1 or HNP-2 SPDS/ERDS data, but not both simultaneously, using display software installed on each PC.

7.9.3 NRC EMERGENCY RESPONSE DATA SYSTEM (ERDS)

The NRC ERDS is a result of the ERDS rule published in the Federal Register (56 FR 40178) under 10 CFR 50. The NRC requires certain plant parametric information in a more timely fashion during plant emergencies than is feasible over the present voice system, the emergency notification system. This has led to a data acquisition system which is manually activated for internet socket transmission of information to the NRC Operations Center on declaration of an ALERT emergency classification or higher. Specific guidance for implementation of this system and offsite communication is given in the references.

7.9.3.1 System Description

The NRC-ERDS functions are provided by software in the SPDS server computer. Once acquired, raw data are converted and prepared for transmission to the NRC.

System activation is one-way, with HNP having control. Activation is accomplished from a terminal located in the TSC which monitors the data link. Since this terminal can be physically switched between plant units, only one is necessary. While system activation is from the plant, termination can be accomplished from the NRC, as well as from the plant.

System design follows the guidance of NUREG 1394, Rev. 1, and fully meets the intent of the ERDS rule.

7.9.3.2 NRC ERDS Data Point Library

The data points used in the NRC ERDS are described in NUREG 1394, Rev. 1, and are essentially a subset of data points used in the SPDS. Pertinent information (in a format provided with the NUREG) on each data point was provided by Georgia Power Company to and subsequently approved by the NRC. This approval finalizes the establishment of the NRC ERDS database. The information is documented in references 3 and 4. The NRC must be informed of any changes to information in this library by a revised copy of the particular data format sheet.

REFERENCES

1. "Emergency Response Data System (ERDS) Implementation," NUREG 1394, Revision 1.

2. NRC Generic Letter 91-14, "Emergency Telecommunications," dated September 23, 1991.

3. Regulatory Issues Summary (RIS) 2009-13, Emergency Response Data System Upgrade From Modem to Virtual Private Network Appliance.

4. Drawing No. A-44047, NRC Emergency Response Data System - Data Point Library (Unit 1).

5. Drawing No. A-51672, NRC Emergency Response Data System - Data Point Library (Unit 2).

7.10 ROD WORTH MINIMIZER (RWM) (HNP-1 AND HNP-2)

7.10.1 DESCRIPTION

Core reactivity control is primarily maintained by the use of moveable control rods interspersed throughout the core. Control rods, which act as absorbers of neutrons in the core, control the reactor power level and provide the primary means of rapidly shutting down the reactor. The control rods are bottom entry and act to reduce the power level as the control rods are inserted upward into the core.

An index tube and drive piston coupled to the control rods are locked at fixed increments by a collet mechanism. Collet fingers prevent unintentional withdrawal of the control rods, but insertion is not restricted. Rod position is sensed by an array of sealed glass reed relay switches contained within a tube. Proximity to an actuating magnet closes an individual reed switch as a permanent magnet attached to the moving piston moves past each switch array.

One of the postulated design basis accidents is a control rod drop accident (CRDA). In this scenario, a control rod becomes uncoupled from its drive mechanism. The drive is then withdrawn while the control rod remains stuck in the reactor core. Subsequently, the rod is released and drops to the drive position, resulting in a sudden reactivity increase. If the reactivity worth of the dropped rod is high, damage to the nuclear system could result. Since the worth of an individual control rod is highly dependent on the core power distribution, rod pattern control provides a means of restricting the maximum reactivity increase which could occur as a result of a CRDA.

A CRDA is credible only at low reactor power (< 10%). Control rod worth is inherently higher at low reactor power. At higher power, control rod worth is minimized by the power distribution.

7.10.2 DESIGN OBJECTIVE

The nuclear measurement analysis and control rod worth minimizer (NUMAC-RWM) is an interlock and display system used to assist the operator in effecting rod pattern control during low-power operations (e.g., startup and shutdown). The principal function of the RWM is to limit rod motion such that high-worth rods are not created, thereby limiting the maximum reactivity increase during a CRDA.

The NUMAC-RWM also limits rod motion so that rods cannot be withdrawn to the extent of generating excessive heat flux in the fuel or causing premature criticality.

7.10.3 RELATED SYSTEMS

The RWM receives input from the rod position information system (RPIS), the reactor manual control system (RMCS), and the power range neutron monitoring system.

The RWM function assists and supplements the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low-power level control rod procedures.

7.10.4 RWM OPERATION

The NUMAC-RWM is automatically initialized on power up, is monitored by the self-test system, and applies both insert and withdraw blocks in the event of failure. The RWM blocking and annunciation functions are automatically bypassed at high-power levels and automatically initiated on power descent.

The NUMAC-RWM prevents the operator from establishing control rod patterns that are not consistent with prestored RWM sequences by initiating appropriate rod insert blocks and rod withdrawal blocks interlock signals to the RMCS rod block circuitry (HNP-1 drawing no. H-19925 and HNP-2 drawing no. H-24784).

The NUMAC-RWM sequences are based on control rod withdrawal procedures designed to limit (and thereby minimize) individual control rod worths to acceptable levels as determined by the design basis CRDA. The NUMAC-RWM can be bypassed during the limited period for which it is used.

The RWM provides automatic supervision to ensure that out-of-sequence control rods are not to be withdrawn or inserted; i.e., limiting operator deviations from the planned withdrawal sequences. The RWM serves as a backup to procedural control of control rod sequence, which limits the maximum reactivity worth of control rods.

In the event the RWM is out of service when required, a second licensed operator, or other qualified member of the technical staff, can manually fulfill the control rod pattern conformance function of this system.

The function of the RWM makes it unnecessary to specify a license limit on rod worth to preclude exceeding applicable event acceptance limit in the event of a CRDA. At low power, below 10%, this device forces adherence to acceptable patterns. Above 10% of rated power, no constraint on rod pattern is required to ensure CRDA consequences are within acceptable limits.

Power level for automatic cutout of the NUMAC-RWM function is sensed by APRM power and the low power setpoints are ~ 21% for both units.

The RWM does not interfere with normal reactor operation and, in the event of a failure, does not cause rod patterns which would violate the objective function to be established. The RWM does not interfere with reactor protection system safety function in either a normal or abnormal condition. The RWM function may be bypassed and its block function disabled only by specific procedural control initiated by the operator.

7.10.5 NUMAC-RWM FUNCTIONS

The RWM is an active interlock system designed to assure that control rod motions conform to a designed sequence, from all rods full-in to the low-power setpoint (LPSP). Control rod motions which would result in a deviation from the designed sequence are inhibited. Sequences conform to the banked-position withdrawal sequence (BPWS) criteria for operation below the LPSP.

The RWM limits rod motion so that rods cannot be withdrawn to the extent of generating excessive heat flux in the fuel causing premature criticality. The RWM displays information relevant to the movement of control rods used to shape both the axial and radial flux profiles for achieving optimum core performance and fuel utilization. When moving control rods in the plant during low-power operation, it is important to avoid achieving control rod configurations which would give any single control rod a high reactivity worth (a high reactivity sensitivity to a change in rod position). The RWM is intended to mitigate the effect of a postulated CRDA which might occur in the unlikely event that a stuck control rod, previously separated from its control rod drive, suddenly exits the core.

The following functions are available on the RWM:

A. Sequence

The operator can select one of four permissible sequences to be enforced by the NUMAC-RWM. The operator is permitted to switch from sequence to sequence at shutdown when the reactor is operating above the LPSP, or when the switching from one sequence to another would not result in any withdrawal or insertion errors.

B. Shutdown Verification

Shutdown verification identifies that a shutdown condition has occurred following a scram and displays the result on the operator display. Shutdown verification requires that all rods be inserted to or beyond a set variable.

C. Shutdown Margin Test

The shutdown margin test permits movement of rods in compliance with the shutdown margin test sequence. One rod can be moved between full-in and full-out. The second rod can be moved between full-in and the shutdown margin.

D. RWM Bypass

In this configuration, the NUMAC-RWM insert block, withdraw block, rod-drive block, settle, and annunciation output contacts are inhibited by the RWM bypass function. The NUMAC-RWM continues to operate and display its intended actions which are inhibited at the RWM buffer.

E. RWM Test Mode

The RWM test mode permits implementation of specific requirements for the test selected. This mode is available when all rods are full-in, or when the existing control rod configuration is permissible for the mode selected.

F. RWM INOP Mode

The RWM INOP mode occurs when the RWM computer front control switch is moved to the INOP position, or when failure impairs the ability of the NUMAC-RWM to perform the sequence control function.

G. Critical Self-Test Failure

A critical self-test failure identifies that one or more RWM functions are impaired by hardware failure. The self-test cycle is more comprehensive when operated in the INOP mode. For this reason, it is advisable to operate the INOP self-test prior to each startup and shutdown to maximize self-test surveillance. Annunciation occurs in all conditions, and rod blocks are applied when the reactor power is below the low-power alarm point.

H. Noncritical Self-Test Failure

One example of a noncritical self-test failure is loss of a redundant power supply. Although noncritical self-test faults do not demand immediate attention, they should be addressed in a timely manner to ensure system performance.

I. Rod Position Substitution

Rod position substitution is permitted for the selected rod when the RPIS-based position data are defective. A calculated rod position, based on prior observed positions, is indicated on the RWM operator display as a recommended substitute value. Any even rod position, 00 to 48 inclusive, can be manually input and substituted.

J. Full-Range Sequence Control Mode

The RWM continues to enforce the pull sequence above the LPSP but conformance to the BPWS criteria is not required. Blocks and block indications are present regardless of the power level. The power indication displays “-SC”, indicating the full-range sequence control is active.