SECTION 1

INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

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SECTION 1

INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 INTRODUCTION

This Final Safety Analysis Report (FSAR) is submitted in support of the application of the Public Service Electric and Gas Company (PSE&G) for a utilization facility (Class 103) license for a nuclear power station designated as Hope Creek Generating Station (HCGS). This station is a one unit nuclear power plant. On August 21, 2000, the operating license for the Hope Creek station was transferred from PSE&G to PSEG Nuclear LLC.

HCGS is located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey. The site is 15 miles south of the Delaware Memorial Bridge, 18 miles south of Wilmington, Delaware, 30 miles southwest of Philadelphia, Pennsylvania, and 7-1/2 miles southwest of Salem, New Jersey.

The unit employs a General Electric boiling water reactor (BWR) licensed to operate at a rated core thermal power of 3902 MWt (100 percent steam flow) with a turbine generator nameplate rating of approximately 1287 MWe. The heat balance for rated power is shown on Figure 1.1-1.

The reactor design power level of 3917 MWt is used in various analyses discussed in Section 6.3 and Section 15. In some analyses, a conservative power level of 4031 MWt is applied.

The Dual Barrier Containment System designed by Bechtel Power Corporation consists of the following:

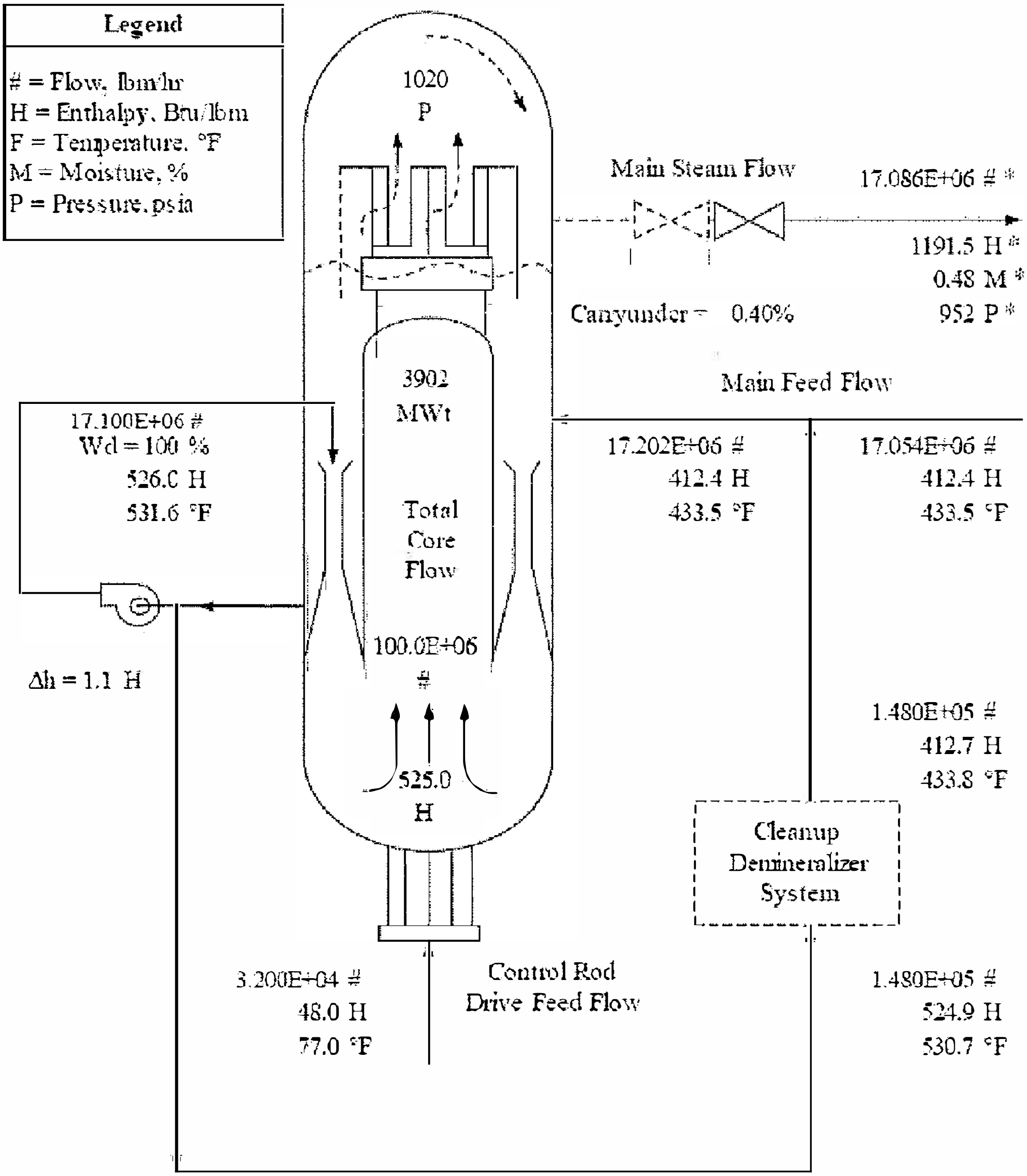
1. The Reactor and the Pressure Suppression Primary Containment System

2. The Reactor Building.

The primary containment is a steel shell, shaped like a light bulb, enclosed in reinforced concrete, and interconnected to a torus type steel suppression chamber. The design employs the drywell/pressure suppression features of the BWR/Mark I containment concept. The Reactor Building completely houses the reactor, the primary containment, and fuel handling and storage areas. To the extent that it limits the release of radioactive materials to the environs, the Reactor Building is capable of containing any radioactive materials that might be released to it, subsequent to the occurrence of a postulated loss-of-coolant accident (LOCA), so that the offsite doses are below the guideline values stated in 10CFR50.67.

Condenser cooling is provided by water circulated through a natural draft cooling tower.

Fuel loading of the HCGS is scheduled for January, 1986. Therefore, receipt of the operating license is required by that date. Based on such receipt, commercial operation of the HCGS is scheduled for June 1986.



*Conditions at upstream side of TSV

Core Thermal Power	3902.0
Pump Heating	10.7
Cleanup Losses	-4.9
Other System Losses	-2.6
Turbine Cycle Use	3905.2 MWt

Revision 23, NOV 12, 2018

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station HEAT BALANCE AT RATED POWER
	Updated FSAR — Figure 1.1-1

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

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1.2 GENERAL PLANT DESCRIPTION

1.2.1 Site Characteristics

A summary of the site characteristics for Hope Creek Generating Station (HCGS) is provided below. Detailed discussions on the site characteristics are provided in Section 2.

1.2.1.1 Location

HCGS is located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey. While called Artificial Island, the site is actually connected to the mainland of New Jersey by a strip of tideland formed by hydraulic fill from dredging operations on the Delaware River by the U.S. Army Corps of Engineers. The site is 15 miles south of the Delaware Memorial Bridge, 18 miles south of Wilmington, Delaware, 30 miles southwest of Philadelphia, Pennsylvania, and 7-1/2 miles southwest of Salem, New Jersey.

1.2.1.2 Meteorology

The area surrounding the Hope Creek site intersects two climatic regions: humid continental and humid subtropical. Both climates are characterized by warm summers and mild winters. Summer maximum temperatures average 80°F, and the coldest month is January with an average daily temperature of approximately 32°F. The maximum temperature reaches 100°F on the average of 1 out of 6 years, and a temperature of 0°F is observed 1 out of 4 years.

The area is frequented by Polar Canadian air masses in the fall and winter and occasionally invaded by Arctic Canadian air late in winter. During the spring and summer, the dominant air mass is Maritime Tropical.

The relative humidity averages 70 to 75 percent because of the proximity of the large water bodies to the south and west of the site and the occurrence of southerly winds. Fog is frequent for the same reason. Southeasterly winds moving along the Delaware Bay at low wind speeds favor this formation of fog.

Rainfall amounts are highest in the summer. Snowfall can be as little as 1 inch or as much as the 50 inches observed one year. Snow is generally mixed with rain and sleet.

1.2.1.3 Site Environs and Access

The site is located in the southern region of the Delaware River Valley, which is defined as the area immediately adjacent to the Delaware River and extending from Trenton to Cape May Point, New Jersey on the eastern side, and from Morrisville, Pennsylvania, to Lewes, Delaware, on the western side. This region is characterized by extensive tidal marshlands and low-lying meadowlands. The major portion of the land in this area is undeveloped. A great deal of land adjacent to the Delaware River near the site is public land (federal- and state-owned), or land planned for future open space projects. In addition, industrial, commercial, or residential growth is limited by recent wetlands and New Jersey CAFRA legislation.

The main access to the plant is from a road constructed by Public Service Electric and Gas Company (PSE&G). This road connects with Alloways Creek Neck Road about 2-1/2 miles east of the site. Access to the plant site and all activities thereon is under the control of PSE&G.

1.2.1.4 Geology and Soil

The site is located within the Atlantic Coastal Plain Physiographic Province and is situated approximately 18 miles southeast of the Fall Line, which separates the Coastal Plain from the Piedmont Physiographic Province.

The pre-Cretaceous basement rock is approximately 1500 to 2000 feet below grade. The sediments of Cretaceous age consist of Raritan

Formation, Magothy Formation, Matawan Group, and Monmouth Group. The sediments of Tertiary age consist of Hornerstown Formation, Vincentown Formation, and Kirkwood Formation. A thin layer of river bed sand and gravel is on top of the Kirkwood clays; approximately 30 feet of hydraulic fill was subsequently placed over this river bed deposit and now forms the surface of the Artificial Island. All Seismic Category I structures are firmly founded on compacted engineering backfill or concrete down to the Vincentown Formation.

1.2.1.5 Seismology

The site is located in the region that has experienced infrequent minor earthquake activities. No known faults exist in the basement rock or sedimentary deposits in the immediate vicinity of the site. Significant earthquake motion is not expected at the site during the life of the facility.

The seismicity of the site was evaluated on the basis of historical earthquake, local and regional geological structures, and associated tectonic provinces. The safe shutdown earthquake (SSE) for the Hope Creek site is conservatively specified as a modified Mercalli Intensity VII plus, with a ground acceleration of 20 percent of gravity. The operating basis earthquake (OBE) is specified with a ground acceleration of 10 percent gravity.

1.2.1.6 Hydrology

The Delaware River Estuary System consists of Delaware Bay, Delaware Estuary, and Delaware River. HCGS is located on the Artificial Island in the Delaware Estuary, approximately 50 river miles upstream of the mouth of Delaware Bay. Tidal flows dominate over fresh water discharge in this area.

The plant grade is generally at Elevation 12.5 feet above mean sea level (MSL), and is subject to maximum design flooding under the effects of probable maximum hurricane surge. All Seismic Category I structures are flood protected and structurally designed to withstand the static and dynamic effects of the flood and coincident waves up to Elevation 31.4 feet MSL. The southeast face of the Reactor Building and a small corner face of the Auxiliary Building, which have exposures to slightly higher waves, are appropriately protected to Elevation 37.2 feet MSL.

The site area is generally flat with natural drainage flowing toward the Delaware River and into the marsh areas toward the north and east. The site drainage system consists of below grade piping and drainage ditches that intercept and convey the runoff to the Delaware River.

1.2.1.7 Groundwater

There are four major aquifers of interest in this region. The confining layers that separate the aquifers are not completely impermeable.

The shallow aquifer is a 5 to 10 foot thick layer of riverbed sand and gravel at 30 feet below grade. The recharge to this aquifer occurs from infiltration of precipitation on the outcrop area within the site, and the discharge is in the southwest direction towards Delaware River.

The deep aquifer is located in the basal sand of lower part of Kirkwood Formation, the Vincentown Formation, and the upper part of Hornerstown Formation. It is 80 feet thick, with its surface at approximately 70 feet below grade. Recharge to this aquifer occurs primarily by leakage from the overlying aquifers, and the discharge is in the southwest direction towards Delaware River.

At 170 feet below grade is the Mount Laurel-Wenonah aquifer, which crops out and intercepts the Delaware River at 5 miles north of the site. Recharge to this aquifer occurs by leakage from overlying aquifers, and the discharge is in the north direction towards Delaware River.

The combined Raritan and Magothy aquifer has a maximum thickness of about 475 feet in their outcrop area, which extends from northeast to southwest from Long Island across New Jersey and Delaware into Maryland. Recharge to this aquifer occurs from precipitation in the outcrop area by infiltration from the surface water and by leakage through the overlying or underlying aquicludes from the aquifers above or below. The discharge is in the direction toward the rivers in the outcrop area.

Groundwater is used for industrial, sanitary, potable, and fire protection purposes at the site. Three production wells were drilled into the Mount Laurel-Wenonah aquifer for Salem Generating Station. Because of salinity concerns, four additional production wells were drilled into the Raritan-Magothy aquifer, two each for Hope Creek and Salem Generating Stations. Most private wells in this region draw water from Mount Laurel-Wenonah aquifer.

1.2.2 Principal Design Criteria

The principal design criteria for the design, construction, and testing of HCGS are presented in two ways. First, they are classified as either a power generation function or a safety function. Second, they are grouped according to system. Although the distinctions between power generation and safety functions are not always clear cut, and sometimes overlap, the functional classification facilitates safety analyses, while the system classification facilitates the understanding of both the system function and design.

1.2.2.1 General Design Criteria

1.2.2.1.1 Power Generation Design Criteria

1. The plant is designed, fabricated, erected, and operated to produce electrical power in a safe and reliable manner. Steam is produced within the nuclear reactor for direct use in the turbine generator unit.

2. Heat removal systems are provided with sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions and abnormal operational transients.

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

4. The fuel cladding, in conjunction with other plant systems, is designed to retain integrity such that any failures shall be within acceptable limits throughout the range of normal operational conditions and abnormal operational transients for the design life of the fuel.

5. Control equipment allows the reactor to respond automatically to load changes and abnormal operational transients.

6. Reactor power level is manually controllable.

7. Control of the reactor is possible from a single location.

8. Reactor controls, including alarms, are arranged to allow the operator to rapidly assess the condition of the reactor system and locate system malfunctions.

9. Interlocks or other automatic equipment are provided as backup to procedural controls to avoid conditions requiring the functioning of nuclear safeguard systems or engineered safety features (ESFs).

10. The station is designed for routine continuous operation whereby steam activation products, fission products,

corrosion products, and coolant dissociation products are processed within acceptable limits.

1.2.2.1.2 Safety Design Criteria

1. The station is designed, fabricated, erected, and operated in such a way that the release of radioactive materials to the environment does not exceed the limits and guideline values of applicable government regulations pertaining to the release of radioactive materials for normal operations and for abnormal transients and accidents.

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

3. The reactor is designed to preclude divergent oscillation of any operating characteristic, to facilitate normal interaction of the reactor with other appropriate plant systems.

4. Gaseous, liquid, and solid waste disposal facilities are designed so that the discharge of radioactive effluents and offsite shipment of radioactive materials can be made in accordance with applicable regulations.

5. The design provides means by which plant operators are alerted when limits on the release of radioactive material are approached.

6. Sufficient indications are provided to determine whether the reactor is operating within the envelope of conditions considered by plant safety analysis.

7. Radiation shielding is provided and access control patterns are established to allow a properly trained operating staff to control radiation doses within the

limits of applicable regulations in any mode of normal plant operations.

8. Those portions of the nuclear system that form part of the reactor coolant pressure boundary (RCPB) are designed to retain integrity as a radioactive material containment barrier following abnormal operational transients and accidents.

9. Nuclear safety systems and ESFs function to ensure that no damage to the RCPB results from internal pressures caused by abnormal operational transients and accidents.

10. Where positive, precise action is immediately required in response to abnormal operational transients and accidents, such action is automatic and requires no decision or manipulation of controls by plant operations personnel.

11. Essential safety actions are provided by systems of sufficient redundance and independence such that no single failure of active components, or of passive components in certain cases, results in the complete failure of a system. For systems or components to which IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations and/or IEEE 308-1978, Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations, applies, single failures of either active or passive electrical components are considered in recognition of the higher anticipated failure rates of passive electrical components relative to passive mechanical components.

12. Provisions are made for control of active components of nuclear safety systems and ESFs from the main control room.

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

14. The design of nuclear safety systems and ESFs includes allowances for natural environmental disturbances such as earthquakes, floods, and storms at the station site.

15. Standby electrical power sources have sufficient capacity to power all nuclear safety systems and ESFs requiring electrical power concurrently.

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

17. The primary containment completely encloses the reactor system, employing the pressure suppression concept.

18. Provisions are made to test the leaktight status and integrity of the primary containment at periodic intervals.

19. A Reactor Building enclosure is provided that completely encloses the primary containment. This building enclosure contains a system for controlling the radioactive materials that may be released from the primary containment.

20. The primary containment and Reactor Building enclosure, in conjunction with other ESFs, limit radiological effects of accidents resulting in the release of radioactive material to the containment volumes to less than the prescribed acceptable limits.

21. Provisions are made for removing energy from the primary containment, as necessary, to maintain the integrity of the containment system following accidents that release energy to the containment.

22. Piping that penetrates the primary containment and could serve as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such uncontrolled radioactive material release is imminent. Such isolation is performed in time to limit radiological effects to less than the specified acceptable limits.

23. Emergency Core Cooling Systems (ECCSs) are provided to limit fuel cladding temperature to less than the limits of 10CFR50.46 in the event of a loss-of-coolant accident (LOCA).

24. The ECCSs provide for continuity of core cooling over the complete range of postulated break sizes in the RCPB.

25. Operation of the ECCSs is initiated automatically when required, regardless of the availability of offsite power supplies and the normal generating system of the station.

26. The main control room and the technical support center are shielded against radiation to allow continued occupancy under accident conditions.

27. In the event that the main control room becomes uninhabitable, it is possible to bring the reactor from power range operation to cold shutdown conditions by using the equipment and local controls that are available outside the main control room.

28. Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup

system has the capability to shut down the reactor from any normal operating condition and subsequently to maintain the cold shutdown condition.

29. Fuel handling and storage facilities are designed to prevent inadvertent criticality and to maintain shielding and cooling of spent fuel.

30. Systems that have redundant or backup safety functions are physically separated and arranged such that any credible event causing damage to any one region of the reactor island complex has minimum prospect for compromising the functional capability of the designated counterpart system.

1.2.2.2 System Criteria

The principal design criteria for particular systems are listed in the following sections.

1.2.2.2.1 Nuclear System Criteria

1. The fuel cladding is designed to retain integrity as a radioactive material barrier, such that any failures are within acceptable limits throughout the design power range.

2. The fuel cladding, in conjunction with other plant systems, is designed to retain integrity such that any failures are within acceptable limits throughout any abnormal operational transient.

3. Those portions of the nuclear system that form part of the RCPB are designed to retain integrity as a radioactive material barrier during normal operation and following abnormal operational transients and accidents.

4. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational transients as well as for abnormal operation transients. The capacity of such systems is adequate to prevent fuel cladding damage.

5. Heat removal systems are provided to remove decay heat generated in the core under circumstances wherein the normal operational heat removal systems become inoperative. The capacity of such systems is adequate to prevent fuel cladding damage. The reactor is capable of being shut down automatically in sufficient time to permit decay heat removal systems to become effective following loss of operation of normal heat removal systems.

6. The reactor core and reactivity control systems are designed so that control rod action is capable of bringing the core subcritical and maintaining it in that condition, even with the rod of highest reactivity worth fully withdrawn and unavailable for insertion.

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

8. The nuclear system is designed to preclude divergent oscillation of any operating characteristic, to facilitate normal interaction of the nuclear system with other appropriate plant systems.

1.2.2.2.2 Power Conversion Systems Criteria

The power conversion systems criteria are discussed below.

1.2.2.2.3 Electrical Power Systems Criteria

Sufficient normal auxiliary and standby sources of electrical power are provided to attain prompt shutdown and continued maintenance of the station in a safe condition. The power sources are adequate to accomplish all required essential safety actions under postulated design basis accident (DBA) conditions.

1.2.2.2.4 Radwaste System Criteria

1. The gaseous and liquid radwaste systems are designed to limit the release of radioactive effluents from the station to the environs to the lowest practical values. Such releases as may be necessary during normal operations are limited to values that meet the requirements of applicable regulations, including 10CFR20 and 10CFR50.

2. The solid radwaste disposal systems are designed so that in-plant processing and offsite shipments are in accordance with all applicable regulations, including 10 CFR 20, 10CFR71, and 49CFR171 through 179 and Department of Transportation Regulations.

3. The systems' designs provide means by which station operations personnel are alerted whenever specified limits on the release of radioactive material may be approached.

1.2.2.2.5 Auxiliary Systems Criteria

1. Fuel handling and storage facilities are designed to prevent criticality and to maintain adequate shielding and cooling for spent fuel. Provisions are made for maintaining the proper chemistry of spent fuel cooling and shielding water.

2. Other auxiliary systems, such as service water, cooling water, fire protection, heating and ventilating,

communications, and lighting, are designed to function during normal and/or accident conditions.

3. Auxiliary systems that are not required to effect safe shutdown of the reactor, or maintain it in a safe condition, are designed such that a failure of these systems shall not prevent the essential auxiliary systems from performing their design functions.

1.2.2.2.6 Radiation Shielding and Access Control Criteria

Where necessary, radiation shielding is provided, and personnel access control patterns are established to allow the plant operating staff to limit radiation exposures to the guideline values of applicable regulations for any mode of normal power operation. Adequate radiation shielding and access control is also provided for abnormal operating conditions such as the release of fission products from failed fuel elements or the contamination of plant areas from system leakage.

Certain vital plant areas, such as the main control room and the technical support center, are shielded and provided with suitable environmental controls.

1.2.2.2.7 Nuclear Safety Systems and Engineered Safety Features Criteria

Principal design criteria for nuclear safety systems and engineered safety features (ESFs) are as follows:

1. These criteria correspond to criteria 10. through 17., 24. through 26., 29., and 30. in Section 1.2.2.1.2.

2. In the event that the main control room is uninhabitable, it is possible to bring the reactor from power range operation to a hot shutdown condition by use of equipment and local controls that are available outside the main

control room. Furthermore, station design allows the operator in these circumstances to bring the reactor to a cold shutdown condition from a hot shutdown condition from outside the main control room.

3. Backup reactor shutdown capability is provided by the Standby Liquid Control System (SLCS). The system is independent of normal reactivity control provisions. This backup system has the capability to shutdown the reactor from any operating condition and subsequently to maintain the shutdown condition.

1.2.2.2.8 Process Control Systems Criteria

The principal design criteria for the process control systems follows.

1.2.2.2.8.1 Nuclear System Process Control Criteria

1. Control equipment is provided to allow the reactor to respond automatically to main load changes within design limits.

2. Provisions are made for manual control of the reactor power level.

3. Control of the nuclear system is possible from a central location.

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

5. Interlocks or other automatic equipment are provided as a backup to procedural controls to avoid conditions requiring the actuation of ESFs.

1.2.2.2.8.2 Power Conversion Systems Process Control Criteria

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

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

3. Control equipment in the feedwater system automatically maintains the water level in the reactor vessel at the optimum level required by steam separators.

4. Control of the power conversion equipment is possible from a central location.

5. Interlocks or other automatic components are provided in addition to procedural controls to avoid conditions requiring the actuation of ESFs.

1.2.2.2.8.3 Electrical Power System Process Control Criteria

1. The Class 1E power systems are designed as an "n" channel system, with any "n-1" channels being adequate to safely shut down the unit.

2. In the event of equipment failure, protective relaying is used to detect and isolate the faulty equipment from the system with a minimum of disturbance.

3. Voltage relays are used on the Class 1E and balance of plant equipment buses to isolate these buses from the normal electrical system, in the event of loss of offsite power (LOP), and to initiate the standby emergency power system diesel generators.

4. The standby emergency power diesel generators are started and loaded automatically to meet the existing emergency condition.

5. Electrically operated breakers are controllable from the main control room.

6. Monitoring of essential generators, transformers, and circuits is provided in the main control room.

7. Controls are provided to ensure that sufficient electrical power is provided for startup, normal operation, prompt shutdown, and continued maintenance of the plant in a safe condition.

1.2.3 General Arrangement of Structures and Equipment

The principal structures at the plant site are as follows:

1. Main power block

    a. Reactor Building with refueling floor

    b. Main control room area of the auxiliary building

    c. Turbine building with turbine generator sets

    d. Radwaste area of the Auxiliary Building

    e. Service area of the Auxiliary Building

    f. Diesel generator area of the Auxiliary Building

2. Circulating water pump structure

3. Cooling tower and water treatment building

4. Sewage treatment plant

5. Service water intake structure

6. Switchyard

7. Administration Building

8. Guardhouse

9. Warehouse area

10. Low-Level Radwaste Storage Facility

11. Independent Spent Fuel Storage Installation (ISFSI)

The arrangement of structures on the site is shown on Plant Drawing C-0001-0. The general arrangement for the major power block structures is shown on Plant Drawings P-0001-0 through P-0007-0 and P-0010-0 through P-0012-0. The equipment arrangement for these structures is shown on the following Plant Drawings: N-1011, P-0012-1 through P-0016-1, P-0031-0 through P-0038-0, P-0042-1 through P-0047-1, P-0051-0 through P-0057-0, P-0072-0, P-0073-0 and P-0076-0.

1.2.4 System Description

A summary of the system description for Hope Creek Generating Station (HCGS) is provided below.

1.2.4.1 <u>Nuclear System</u>

The nuclear system includes a direct cycle, forced circulation, General Electric (GE) boiling water reactor (BWR) that produces steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear system for the rated power conditions is shown on Figures 10.1-1 and 10.1-2.

1.2.4.1.1 Reactor Core and Control Rods

The reactor core and control rods are described in Section 1 and Appendix A, Subsection A.1.2.2.3.1 of Reference 1.2-1.

1.2.4.1.2 Reactor Vessel and Internals

The reactor vessel contains the core and supporting structures, steam separators and dryers, jet pumps, control rod guide tubes, distribution lines for the feedwater, core sprays, core differential pressure and liquid control lines, in-core instrumentation, and other components. The main connections to the vessel include steam lines, coolant recirculation lines, feedwater lines, control rod drive (CRD) and in-core nuclear instrument housings, core spray lines, core differential pressure line, jet pump pressure sensing lines, water level instrumentation, and CRD system return lines (capped).

The reactor vessel is designed and fabricated in accordance with applicable codes for a pressure of 1250 psig. The nominal operating pressure in the steam space above the separators is 1020 psia. The vessel is fabricated of low alloy steel and is clad internally with stainless steel (except for the top head, which is not clad).

The reactor core is cooled by demineralized water that enters the lower portion of the core and boils as it flows upward around the fuel rods. The steam leaving the core is dried by steam separators and dryers located in the upper portion of the reactor vessel. The steam is then directed to the turbine through the main steam lines. Each steam line is provided with two automatic containment isolation valves in series; one on each side of the primary containment barrier.

1.2.4.1.3 Reactor Recirculation System

The Reactor Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each loop has one motor driven recirculation pump powered and controlled by a dedicated motor generator set located outside the primary containment. Recirculation pump speed can be varied, to allow some control of reactor power level through the effects of coolant flow rate on the moderator void content.

The jet pumps are reactor vessel internals. The jet pumps provide a continuous internal circulation path for the major portion of the core coolant flow. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Any recirculation line break would still allow core flooding to approximately two-thirds of the core height, the level of the jet pumps' inlet.

1.2.4.1.4 Residual Heat Removal System

The Residual Heat Removal (RHR) System is a system of pumps, heat exchangers, and piping that fulfills the following functions:

1. Removes decay and sensible heat during and after plant shutdown

2. Injects water into the reactor system, following a LOCA, to reflood the core independent of other core cooling systems as discussed in Section 1.2.4.2.8.

3. Removes heat from the primary containment, following a LOCA, to limit the increase in primary containment pressure. This is accomplished by cooling and recirculating the suppression pool water (containment cooling) and, if desired, by spraying the drywell and suppression pool air spaces (containment spray) with suppression pool water.

1.2.4.1.5 Reactor Water Cleanup System

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

1.2.4.1.6 Nuclear Leak Detection System

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

1. Main steam lines

2. RWCU system

3. RHR system

4. Reactor Core Isolation Cooling (RCIC) System

5. Feedwater system

6. Emergency Core Cooling Systems (ECCS)

7. Other miscellaneous systems, such as Safety Auxiliaries Cooling System (SACS) heat exchanger room, reactor building equipment drain sump, etc.

Small leaks generally are detected by monitoring the air coolers' condensate flow inside the drywell, airborne radiation levels, and drain sump fillup and pumpout rates. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

1.2.4.2 Nuclear Safety Systems and Engineered Safety Features

1.2.4.2.1 Reactor Protection System

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

1.2.4.2.2 Neutron Monitoring System

Those portions of the neutron monitoring system that form part of the RPS qualify as a nuclear safety system. The intermediate range monitors (IRM) and the average power range monitors (APRM), which monitor neutron flux via in-core detectors, provide scram logic inputs to the RPS. Thus, a scram is initiated in time to prevent excessive fuel clad damage as a result of over power transients. The APRM system also generates a simulated thermal power signal. Both Neutron Flux - Upscale and upscale simulated thermal power are conditions that provide scram logic signals.

1.2.4.2.3 Control Rod Drive System

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

1.2.4.2.4 Control Rod Drive Housing Supports

CRD housing supports are located underneath the reactor vessel near the control rod housings. The supports limit the travel of a control rod in the event that a control rod housing is ruptured.

1.2.4.2.5 Control Rod Velocity Limiter

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

1.2.4.2.6 Nuclear System Pressure Relief System

A Pressure Relief System consisting of 14 safety/relief valves mounted on the main steam lines is provided to prevent excessive pressure inside the nuclear system for operational transients or accidents.

1.2.4.2.7 Reactor Core Isolation Cooling System

The RCIC system provides makeup water to the reactor vessel when the vessel is isolated. The RCIC system uses a steam driven turbine pump unit and operates automatically, with sufficient coolant flow to maintain adequate water level in the reactor vessel for events defined in Section 5.4.6.

1.2.4.2.8 Emergency Core Cooling Systems

In the event of a breach in the RCPB that results in a loss of reactor coolant, four ECCSs are provided to maintain fuel cladding below the temperature limit of 10CFR50.46. The systems are:

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

2. Automatic Depressurization System (ADS) - The ADS rapidly reduces reactor vessel pressure during a LOCA in which the HPCI system fails to maintain the reactor vessel water level. The depressurization provided by the system enables the low pressure ECCSs to deliver cooling water to the reactor vessel. The ADS uses some of the relief valves that are part of the Nuclear System Pressure Relief System. The automatic relief valves are arranged to open on conditions indicating both a break in the reactor coolant pressure boundary (RCPB) and a failure of the HPCI system to deliver sufficient cooling water to the reactor vessel to maintain the water level above a preselected value. The ADS will not be actuated unless either the core spray or RHR pumps (in the LPCI mode) are operating. This ensures that adequate coolant will be available to maintain reactor water level after depressurization.

3. Core spray - The Core Spray System consists of two independent pump loops that deliver cooling water to spray spargers over the core. The system is actuated by conditions indicating that a breach exists in the nuclear system process barrier, but water is delivered to the core only after reactor vessel pressure is reduced to below the pump shutoff head. This system provides the capability of cooling the fuel by spraying water onto the core. Either core spray loop, in conjunction with the ADS, or HPCI system by itself, can provide sufficient fuel cladding cooling following a LOCA.

4. Low pressure coolant injection (LPCI) - LPCI is an operating mode of the RHR system, but is discussed here because the LPCI mode acts as an ESF in conjunction with the other ECCSs. LPCI uses the pump loops of the RHR to inject cooling water into the reactor system. LPCI is actuated by conditions indicating a breach in the RCPB, but water is delivered to the core only after reactor vessel pressure is reduced to below the pump shutoff head.

LPCI operation provides the capability of core reflooding, following a LOCA, in time to maintain the fuel cladding below the prescribed temperature limit.

1.2.4.2.9 Containment

1.2.4.2.9.1 Functional Design

The containment system offsets the consequences of a breach of the reactor pressure vessel (RPV) and fuel by limiting the discharge of radioactive products, as prescribed by federal regulations.

Primary containment and Reactor Building enclosure barriers have been provided. The former employs the pressure suppression concept. The latter includes a low leakage Reactor Building and a Filtration, Recirculation, and Ventilation System (FRVS).

The primary containment is designed to remain intact before, during, and after a design basis accident (DBA). The design employs a pressure suppression primary containment that houses the reactor vessel, the coolant recirculation loops, and other branch connections of the primary system. The pressure suppression chamber (torus) stores a large volume of water and consists of a connecting vent system between the drywell and the pressure suppression pool, and isolation valves.

In the event of a process system piping failure within the drywell, reactor water and steam are released into the drywell air space. 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. Air transferred to the suppression pool is subsequently vented through the vacuum breakers to the drywell to equalize the pressure between the two areas. Heat from the reactor core, the drywell, and the torus is removed by the containment cooling systems. Containment isolation valves ensure that the released radioactive materials are confined to the primary containment.

1.2.4.2.9.2 Heat Removal

The Containment Heat Removal System is summarized in Section 1.2.4.2.14.

1.2.4.2.9.3 Containment Spray

The Containment Spray System consists of two redundant subsystems, each with its own full capacity spray header. Each subsystem is supplied from a separate redundant RHR subsystem. This system is provided as a means of reducing the containment pressure following a LOCA.

1.2.4.2.9.4 Combustible Gas Control

The level of combustible gas in the containment environment during a beyond design basis accident is controlled by two redundant thermal hydrogen recombiners. The recombiner trains are separated into mechanical and electrical divisions. During reactor normal operations, containment purging capability is provided through the Reactor Building Ventilation System (RBVS).

1.2.4.2.10 Containment and Reactor Vessel Isolation Control System

The containment and reactor vessel isolation control system automatically initiates closure of isolation valves to close off all process lines that are potential leakage paths for radioactive material to the environs. This action is taken upon indication of a breach in the RCPB.

1.2.4.2.11 Main Steam Isolation Valves

Although all pipelines that both penetrate the containment and offer a potential release path for radioactive material are provided with redundant isolation capabilities, the main steam lines, because of their large size and large mass flow rates, are given special isolation consideration. Automatic isolation valves are provided in each main steam line. Each is powered by both air pressure and spring force. These valves accomplish the following objectives:

1. Prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the reactor vessel (as such a loss could derive either from a major leak in the steam piping outside the containment or from a malfunction of the pressure control system, resulting in excessive steam flow from the reactor vessel).

2. Limit the release of radioactive materials from the fuel to the reactor cooling water and steam by isolating the RCPB

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

1.2.4.2.12 Main Steam Line Flow Restrictors

A venturi type flow restrictor is installed in each steam line. These devices limit the loss of coolant from the reactor vessel before the main steam isolation valves (MSIVs) are closed, in the event of a main steam line break outside the containment.

1.2.4.2.13 Main Steam Line Radiation Monitoring System

The main steam line radiation monitoring system consists of four gamma radiation monitors located externally to the main steam lines just outside the containment. The monitors are designed to detect a gross release of fission products from the fuel.

1.2.4.2.14 Residual Heat Removal System (Containment Cooling)

The containment cooling subsystem is placed in operation to limit the temperature of water in the suppression pool and of the atmospheres in the drywell and suppression chamber following a design basis LOCA; to control the pool temperature during normal operation of the main steam safety/relief valves (SRVs) and the RCIC system, and to reduce the pool temperature following an isolation transient. In the containment cooling mode of operation, the RHR main system pumps take suction from the suppression pool and pump the water through the RHR heat exchangers where cooling takes place by transferring heat to the SACS, which in turn transfers the heat to the service water system. The fluid is then discharged back to the suppression pool, to the drywell spray header, or to the suppression chamber spray header.

1.2.4.2.15 Ventilation Exhaust Radiation Monitoring System

The Process Ventilation Radiation Monitoring System consists of a number of radiation monitors arranged to monitor the activity level of the air exhaust from the Containment and Reactor Building, Auxiliary Building, radwaste area Auxiliary Building laboratories, fuel handling pool, and Turbine Building.

1.2.4.2.16 Filtration, Recirculation, and Ventilation System (FRVS)

The FRVS confines, controls, and collects the airborne contamination released to the Reactor Building as a result of any abnormal incident. By mixing and filtering the Reactor Building atmosphere, and by maintaining the Reactor Building under negative pressure with respect to outdoors, the system limits the release of radioactivity. Redundant trains of fans, filters, controls, etc, have been provided along with emergency power to ensure system operation and reliability.

1.2.4.2.17 Power Supply

1.2.4.2.17.1 Standby AC Power Supply

The standby ac power supply system consists of four independent diesel generators. Each of the four Class 1E load groups is fed from its own dedicated standby diesel generator (SDG). Each SDG starts automatically upon LOP or LOCA. SDGs are designed to start and be ready to accept load within 10 seconds after receipt of a start signal. Three out of the four SDGs provide adequate capacity to operate all the equipment necessary to prevent undue risk to public health and safety in the event of total LOP or DBAs. No provision is made to parallel any two Class 1E SDGs under any operating conditions.

1.2.4.2.17.2 Non-Class 1E AC Power Supply

The non-Class 1E ac systems consist of 7.2 kV and 4.16 kV switchgear, 480 V unit substation switchgear, motor control centers (MCCs), and 120 V panels. These systems supply power to balance of plant equipment.

1.2.4.2.18 DC Power Supply

1.2.4.2.18.1 Class 1E DC Power Supply Systems

HCGS is provided with four independent 125 V and two 250 V dc Class 1E channels. Each dc system is supplied from an independent battery and battery chargers. Each 125 V dc bus supplies control power for Class 1E equipment in its own load group. Both 250 V dc systems, one of which is dedicated to the HPCI system and the other to the RCIC system, operate the valves and vacuum pumps in their respective systems. The Class 1E 125 V and 250 V dc systems are designed to supply sufficient power to satisfy the ESF load requirements of a postulated LOP and any concurrent single failure in the dc system.

1.2.4.2.18.2 Non-Class 1E DC Power Supply Systems

The station is provided with two ±24 V, five 125 V, and one 250 V dc power systems. Each dc system is supplied by an independent battery and battery chargers.

The 24 V dc systems supply power for the Neutron Monitoring System (NMS). The 125 V dc systems supply control power for non-Class 1E systems and power for some of the equipment important for plant operation. A 250 V dc bus supplies power for auxiliary equipment important for the reactor recirculation motor generator set, the reactor feed pump turbine (RFPT), and the main turbine generator unit.

1.2.4.2.19 Standby Liquid Control System

Although not intended to provide prompt reactor shutdown, as are the control rods, the SLC system provides a redundant, independent, and alternate way to bring the nuclear fission reaction to subcriticality and to maintain subcriticality as the reactor cools. The system makes possible an orderly and safe shutdown in the event that the number of control rods inserted into the reactor core is insufficient to accomplish shutdown in the normal manner. The system is sized to counteract the positive reactivity effect from rated power to the cold shutdown condition.

1.2.4.2.20 Safe Shutdown from Outside the Main Control Room

In the event that the main control room becomes inaccessible, the reactor can be brought from power range operation to cold shutdown conditions by means of the local controls and components that are available outside the main control room.

1.2.4.2.21 DELETED

1.2.4.3 Power Conversion System

1.2.4.3.1 Turbine Generator

The turbine generator consists of the turbine, generator, exciter, controls, and required subsystems designed for a nameplate 1287 MWe plant rating.

The turbine is an 1800 rpm, tandem compound, six flow, nonreheat unit with 43-inch last stage buckets and a digital electrohydraulic control system. The main turbine include one double flow high pressure turbine and three double flow low pressure turbines. Exhaust steam from the high pressure turbine passes through moisture separators before entering the three low pressure turbines.

The generator is a direct drive, three phase, 60 hertz, 25,000 V, 1800 rpm, with the rotor hydrogen cooled and the stator conductors water cooled, synchronous generator rated on the basis of guaranteed best turbine efficiency megawatt rating at 0.94 power factor and 75 psig hydrogen pressure. The generator exciter system is shaft driven, complete with a static type voltage regulator and associated switchgear. The turbine generator auxiliary systems are as follows:

1. Generator Gas Control System

2. Generator Seal Oil System

3. Turbine Lube Oil System

4. Steam Seal System

5. Generator Stator Cooling System.

1.2.4.3.2 Main Steam System

The Main Steam System delivers steam from the Nuclear Boiler System through four 28-inch steam lines to the turbine generator. This system also supplies steam to the steam jet air ejectors (SJAEs), the reactor feed pump turbines (RFPTs), the main condenser hotwell, and the steam seal evaporator.

1.2.4.3.3 Main Condenser

The main condenser is a two pass, single pressure, deaerating type. The condenser consists of three shells, each with two tube bundles, two inlet/outlet waterboxes, and two reversing end waterboxes. Each shell is located below one of three low pressure turbines. Rubber expansion joints are provided between each turbine exhaust opening and the steam inlet connections in the condenser shells.

During normal operation, steam from the low pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings and is condensed. The condenser also serves as a heat sink for several other flows, i.e., exhaust steam from the RFPTs, feedwater heater shell operating vents, and other components in the heat cycle.

During abnormal conditions, the condenser is designed to receive one or more streams from turbine bypass steam, feedwater heater high level dump(s), and relief valve discharge from moisture separators, feedwater heater shells, and various steam supply lines.

Other flows occur periodically. They originate from condensate pump and reactor feed pump startup vents, reactor feed pump and condensate pump minimum recirculation flows, and feedwater line startup vents; turbine equipment clean drains and low point drains; deaerating steam, makeup, condensate, etc.

1.2.4.3.4 Main Condenser Air Removal

The main condenser air removal system removes the noncondensable gases from the main condenser and exhausts them to the off-gas system. Two, 100 percent capacity SJAEs are provided for air removal during normal operation. Two 100 percent capacity motor-driven vacuum pumps are provided for air removal during startup.

1.2.4.3.5 Turbine Gland Seal System

The Steam Seal System provides steam to the seals of the turbine valve packings and the turbine shaft packings. The sealing steam is supplied by the seal steam evaporator. An auxiliary boiler provides an auxiliary steam supply for startup and when the seal steam evaporator is not operating.

1.2.4.3.6 Turbine Bypass System and Pressure Control System

A Turbine Bypass System is provided that passes steam controlled by a pressure regulator directly to the main condenser. Steam is bypassed to the condenser whenever the reactor steaming rate exceeds the load permitted to pass to the turbine generator. The capacity of the Turbine Bypass System is 21.75 percent of the reactor rated steam flow. The pressure regulation system provides main turbine control valve and bypass valve flow demands so as to maintain a nearly constant reactor pressure during normal plant operation.

1.2.4.3.7 Circulating Water System

The Circulating Water System (CWS) is designed to circulate the flow of water required to remove the heat load from the main condenser and other auxiliary equipment and to discharge it to the atmosphere through a natural draft cooling tower.

1.2.4.3.8 Condensate Demineralizer System

The function of the condensate demineralizer system is to maintain the required purity of the feedwater flowing to the reactor. The system consists of full flow, deep bed demineralizers using ion exchange resins that remove dissolved and suspended solids from the feedwater to maintain the feedwater purity necessary for the reactor. The demineralizers also remove some of the radioactive material produced by corrosion and fission product carryover from the reactor. The radioactivity from these sources does not have a significant effect on the resins.

The condensate pre-filter system is located upstream of the existing deep bed demineralizers to improve iron removal and reduce radwaste. The condensate pre-filter system is described in 1.2.4.3.11.

1.2.4.3.9 Condensate and Feedwater System

The condensate and feedwater system is designed to deliver the required feedwater flow to the reactor vessels during stable and transient operating conditions, throughout all modes of operation, including startup to full load to shutdown. The system uses three primary condensate pumps to pump deaerated condensate from the hotwell of the main condenser through the air ejector condenser, the gland steam condenser, and in turn to the condensate demineralizer. The three secondary condensate pumps then pump demineralized feedwater through three parallel strings of feedwater heaters, each string consisting of five heaters, to the suction of three reactor feed pumps that deliver feedwater to the reactor through the sixth feedwater heater.

1.2.4.3.10 Condensate and Refueling Water Storage and Transfer System

The function of the Condensate and Refueling Water Storage and Transfer System is to store condensate and employ it to accomplish the following objectives:

1. Supply water for the RCIC and HPCI systems
2. Maintain the required condensate level in the hotwell by supplying condensate to the main condensate system to make up for a deficiency and receive excess condensate rejected from the main condensate system at the secondary condensate pump suction side
3. Fill the reactor well during refueling and receive this water back for storage after it has been cleaned by the demineralizer

4. Provide condensate where required for miscellaneous equipment in the radwaste and Reactor Buildings.

Makeup water to the condensate storage tanks (CSTs) is provided by the demineralized water storage tank.

1.2.4.3.11 Condensate Pre-filter System

The function of the Condensate Pre-filter system is to remove insoluble impurities, primarily iron, from the condensate upstream of the deep bed demineralizers.

The Condensate Pre-filter System consists of four vessels operated in parallel with a 33% bypass valve. The filter system is designed to operate at 100% condensate flow with a filter flux flow of approximately 0.32 gpm/ft^2 with all four filter vessels in service. The Condensate Pre-filter System is designed to remove iron to less than 1ppb. Automatic valves operated by the Condensate Pre-filter control system remove the individual filter vessels from the process stream and backwash the filter media. Backwash water is collected in a header and directed to the Backwash Receiving Tank (BWRT). The BWRT is pumped to the radwaste system.

1.2.4.4 Electrical Systems and Instrumentation and Control

Four independent Class 1E 208/120 V ac power systems are provided. Each is dedicated to its own instrumentation channel. Control power supply for Class 1E 4.16-kV and 480 V switchgear is supplied from the corresponding channel 125 V dc system. Starters in the MCCs derive their control power from the control power transformers located in the starter cubicle.

1.2.4.4.1 Electrical Power Systems

1.2.4.4.1.1 Generation and Transmission Systems

The main generator is a 1373.1 MVA, 1800 rpm, 0.94 power factor, 25,000 V, three phase, 60 hertz, 0.50 scr, 75 psig hydrogen cooled synchronous machine. The stator is water cooled. The generator is connected directly to the turbine shaft. Excitation is from a shaft driven alternator and stationary rectifier banks. The generator neutral is grounded through a 75-kVA, single phase, 14,400 120/240 V distribution transformer. The main generator unit is connected to the PSE&G 500-kV switchyard through three single phase 24 500-kV main stepup transformers. The Hope Creek 500-kV switchyard is tied to the Pennsylvania New Jersey Maryland interconnected power network by three physically independent aerial transmission lines.

1.2.4.4.1.2 Electric Power Distribution Offsite AC Systems Power Supply

Arrangement of the switchyard provides a reliable and redundant offsite auxiliary power supply. Power from the 500 kV switchyard to a 13.8-kV ring bus is fed through two physically independent paths.

The 13.8-kV ring bus feeds both Class 1E and non Class 1E ac and dc power systems. The Class 1E power system supplies all safety related equipment and some non Class 1E loads that are important for plant operation. The non Class 1E power system applies to the balance of plant equipment. The Class 1E ac system consists of four independent load groups. Each load group includes 4.16 kV switchgear, 480 V unit substations, 480 V MCCs, and 120 V control and instrument power panels. The vital ac instrumentation and control power supply systems include dc battery systems and static inverters.

1.2.4.4.2 Nuclear System Process Control and Instrumentation

1.2.4.4.2.1 Reactor Manual Control System

The Reactor Manual Control System provides the means by which control rods are positioned from the main control room for power control. The system operates valves in each hydraulic control unit to change control rod position. Only one control rod can be manipulated at a time. The Reactor Manual Control System includes logic that restricts control rod movement (rod block) under certain conditions as a backup to procedural controls.

1.2.4.4.2.2 Recirculation Flow Control System

The Recirculation Flow Control System controls the speed of the reactor recirculation pumps. Adjusting the pump speed changes the coolant flow rate through the core. This effects changes in core power level.

1.2.4.4.2.3 Neutron Monitoring System

The Neutron Monitoring System (NMS) is a system of in-core neutron detectors and out-of-core electronic monitoring equipment. The system provides indication of neutron flux, which can be correlated to thermal power level for the entire range of flux conditions that can exist in the core. The source range monitors (SRMs) and the intermediate range monitors (IRMs) provide flux level indications during reactor startup and low power operation. The local power range monitors (LPRMs) and average power range monitors (APRMs) allow assessment of local and overall flux conditions during power range operation. The traversing in core probe system (TIP) provides a means to calibrate the individual LPRM sensors. The NMS provides inputs to the reactor manual control system to initiate rod blocks if preset flux limits are exceeded, and inputs to the RPS to initiate a scram if other limits are exceeded.

1.2.4.4.2.4 Refueling Interlocks

A system of interlocks that restricts movement of refueling equipment and control rods when the reactor is in the refueling and startup modes is provided to prevent an inadvertent criticality during refueling operations. The interlocks back up procedural controls that have the same objective. The interlocks affect the refueling platform, refueling platform main hoist, fuel grapple, and control rods.

1.2.4.4.2.5 Reactor Vessel Instrumentation

In addition to instrumentation for the nuclear safety systems and engineered safety features (ESFs), instrumentation is provided to monitor and transmit information that can be used to assess conditions existing inside the reactor vessel and the physical condition of the vessel itself. This instrumentation monitors reactor vessel pressure, water level, coolant temperature, reactor core differential pressure, coolant flow rates, and reactor vessel head inner seal ring leakage.

1.2.4.4.2.6 Process Computer System

An online process computer is provided to monitor and log process variables and to make certain analytical computations. This system is part of the CRIDS System. An off-line computer program, which duplicates the process computer core evaluation functions, may be used in the event the online system is unavailable.

1.2.4.4.3 Power Conversion Systems Process Control and Instrumentation

1.2.4.4.3.1 Pressure Regulator and Turbine Generator Control

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

The turbine generator speed load control algorithms act to maintain the turbine speed (generator frequency) at a constant rate.

The turbine generator speed load controls can initiate rapid closure of the turbine control valves and rapid opening of the turbine bypass valves to prevent turbine overspeed on loss of the generator electric load or a power/load unbalance event.

1.2.4.4.3.2 Feedwater Control System

The Feedwater Control System automatically controls the flow of feedwater into the RPV to maintain the water within the vessel at predetermined levels. A conventional three element flow control system is used to accomplish this function.

1.2.4.5 Fuel Handling and Storage Systems

1.2.4.5.1 New and Spent Fuel Storage

New and spent fuel storage racks are designed to prevent inadvertent criticality and load buckling. Sufficient coolant and shielding are maintained to prevent overheating and excessive personnel exposure, respectively. The design of the fuel pool provides for corrosion resistance, adherence to Seismic Category I requirements, and prevention of k_{eff} from reaching 0.95 under dry or flooded conditions.

1.2.4.5.2 Fuel Handling System

The fuel handling equipment includes a fuel inspection stand, fuel preparation machine, a bridge crane, a refueling platform, a new fuel transfer basket, a 360 Degree Scorpion II service platform, jib cranes, and other related tools for fuel and reactor servicing. All equipment conforms to applicable codes and standards.

1.2.4.5.3 Independent Spent Fuel Storage Installation (ISFSI)

Interim storage of spent fuel is available at the on-site ISFSI, pursuant to satisfying the general license requirements of 10 CFR 72, Subpart K. Details pertaining to the design and operation of the ISFSI, including the design and safety analyses for the spent fuel storage casks, may be found in the site 10 CFR 72.212 evaluation report and the dry spent fuel storage system Certificate of Compliance (CoC) and FSAR.

1.2.4.6 Cooling Water and Auxiliary Systems

1.2.4.6.1 Safety and Turbine Auxiliaries Cooling System

The SACS, a portion of the Safety and Turbine Auxiliaries Cooling System (STACS), supplies cooling water to essential reactor components during normal and accident modes of operation. During normal operation, the Turbine Auxiliary Cooling System (TACS), a portion of the STACS, also cools the turbine auxiliary equipment. Heat is transferred from the SACS to the service water system.

The system consists of two 100 percent capacity loops with two pumps and two heat exchangers per loop.

During normal operation, one loop is in service, and the other loop in automatic standby. Each loop is isolated from the other loop to eliminate the possibility of a single event causing loss of the entire system.

1.2.4.6.2 Reactor Auxiliary Cooling System

The Reactor Auxiliary Cooling System (RACS) cools the nonsafety related reactor and radwaste equipment during normal, LOP, and shutdown conditions. The RACS transfers its heat to the service water system.

The system consists of two pumps and two heat exchangers. One pump and one heat exchanger are required for plant loads, except for the cooling of the radwaste systems, which requires two pumps and two heat exchangers to operate.

1.2.4.6.3 Fuel Pool Cooling and Cleanup System

The Fuel Pool Cooling and Cleanup (FPCC) System is provided to remove decay heat from spent fuel stored in the fuel pool and to maintain specified water temperature, purity, clarity, and level.

The fuel pool filter demineralizer subsystem is also used by the Torus Water Cleanup (TWC) System.

1.2.4.6.4 Station Service Water System

The Station Service Water System (SSWS) consists of two redundant trains that provide river water to cool the SACS heat exchangers and the Reactor Auxiliaries Cooling System (RACS) heat exchangers.

1.2.4.6.5 Ultimate Heat Sink (UHS)

The ultimate heat sink (UHS) for HCGS engineered safety equipment is the Delaware River. The UHS provides the required cooling water for the startup, normal operation, accident, or shutdown conditions of the reactor.

During normal operation, the UHS is designed to dissipate heat by discharging heated water into the circulating water system. This system dissipates this heat and the heat rejected in the main condenser to the atmosphere by a natural draft cooling tower by evaporation, with the overflow going to the Delaware River.

During LOCA or LOP conditions, the UHS provides the necessary reliable heat sink for the safeguard equipment. The cooling tower is not essential for the safe shutdown of the plant.

1.2.4.6.6 Raw Water Treatment Plant and Makeup Water Treatment System

A Makeup Water Treatment System is provided to furnish a supply of treated water suitable for plant use.

1.2.4.6.7 Potable and Sanitary Wastewater System

The Potable and Sanitary Wastewater System provides water for drinking, makeup, and sanitary services.

1.2.4.6.8 Plant Chilled Water System

The plant CWS is designed to provide a means of cooling both the fresh air supply and air recirculation to building HVAC systems.

1.2.4.6.9 Process Sampling System

The Process Sampling System furnishes process information that is required to monitor plant and equipment performance and changes in operating parameters. Representative liquid and gas samples are taken automatically and/or manually during normal plant operation and under accident conditions for laboratory or online analyses.

1.2.4.6.10 Plant Equipment and Floor Drainage

The Plant Equipment and Floor Drainage Systems include both radioactive and nonradioactive drains. Radioactive drains contain potentially radioactive materials and are pumped to the radwaste system for cleanup, reuse, or disposal. Nonradioactive drain materials are treated to remove oil prior to discharge to the Delaware River. The Turbine Building Circulating Water Dewatering Sump may be contaminated with low levels of tritium from certain supply ventilation HVAC drains.

1.2.4.6.11 Service and Instrument Air Systems

The Service Air System supplies filtered, oil free, compressed air for plant operation and services.

The Instrument Air System supplies filtered, dried, and oil free compressed air for air operated instruments.

The breathing air system supplies filtered, dried, oil free, and purified compressed air for operating and maintenance personnel working in hazardous areas.

1.2.4.6.12 Diesel Generator Fuel Oil Storage and Transfer System

The diesel generators are located inside the Auxiliary Building. The fuel oil storage tanks, two per diesel generator, are located below the engines, and each tank has a capacity of 26,500 gallons of oil. It takes 53,000 gallons of oil to run one diesel generator at 4340 kW continuously for 7 days. Each diesel generator unit has its own fuel oil day tank. The tank is mounted above the unit for gravity feed of diesel fuel at startup. This tank's capacity is about 550 gallons. The diesel generator is a self sustaining unit with its own lube oil and fuel oil system.

1.2.4.6.13 Auxiliary Steam System

The Auxiliary Steam System consists of three water tube boilers, a deaerator, three boiler feedwater pumps, and associated piping and instrumentation. The system is designed to accommodate varying steam demands during all operating modes.

1.2.4.6.14 Heating, Ventilating, and Air Conditioning (HVAC)/ Environmental Systems

The HVAC systems supply and circulate filtered fresh air for personnel comfort and equipment cooling.

1.2.4.6.15 Lighting Systems

The Plant Lighting System is designed to provide adequate lighting during all plant operating and maintenance conditions. Illumination levels provided in various areas either conform to or exceed those required in the IES handbook. The Plant Lighting System consists of normal, essential, standby, and standby self contained 8 hour battery pack units. The integrated design of the lighting systems provides adequate station lighting in all areas required for maintenance of safety related equipment, firefighting, and access routes to and from these areas.

1.2.4.6.16 Fire Protection System

A Fire Protection System (FPS) supplies firefighting water to automatic fire suppression systems and hose stations located throughout the plant. A carbon dioxide protection system is provided in addition to portable fire extinguishers in some areas of the plant, such as the diesel generator rooms, diesel fuel tank rooms, and at turbine generators in the Turbine Building, etc.

1.2.4.6.17 Communications Systems

The Plant Communication System provides for personnel communication between various locations in buildings and also between various buildings.

1.2.4.7 Radioactive Waste Systems

1.2.4.7.1 Gaseous Radwaste System

The purpose of the Gaseous Radwaste System is to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to persons outside the controlled area does not exceed the maximum limits of the applicable 10CFR regulations, even in the case of defective fuel rods.

The off-gases from the main condenser are the major source of gaseous radioactive waste. The treatment of these gases includes volume reduction through a catalytic hydrogen oxygen recombiner; water vapor removal through a condenser; decay of short lived radioisotopes through a holdup line; further condensation and cooling, filtration, adsorption of isotopes on activated charcoal beds; further filtration through high efficiency filters; and final releases.

Continuous radiation monitors are provided that indicate radioactive release from the reactor and from the charcoal adsorbers. The radiation monitors are used to isolate the off-gas system on high radioactivity in order to prevent gas releases of unacceptably high activity.

1.2.4.7.2 Liquid Radwaste System

The Liquid Radwaste System collects, treats, stores, and disposes of all radioactive liquid wastes. These wastes are collected in sumps and drain tanks at various locations throughout the plant and then transferred to the appropriate collection tanks in the radwaste building for processing. Processed liquid wastes are returned to the condensate system, transferred to the solid radwaste system for dewatering and packaging for offsite shipment, or discharged from the plant. Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance within radiation allowances for personnel exposure.

Valving redundancy, instrumentation for detection, alarms of abnormal conditions, and procedural controls protect against the accidental discharge of liquid radioactive waste.

1.2.4.7.3 Solid Radwaste System

Solid radioactive wastes originating from the Nuclear Steam Supply System (NSSS) equipment are stored for radioactive decay in the fuel storage pool and prepared for reprocessing or offsite storage in approved shipping containers. Examples of these wastes include spent control rods and in core ion chambers.

Process solid wastes are collected, dewatered, concentrated, solidified, packaged, and stored in a shielded compartment prior to offsite shipment in approved shipping containers. Examples of these wastes include: filter residue, spent resins, evaporator bottoms, and dry waste.

1.2.4.8 Radiation Monitoring and Control

1.2.4.8.1 Process Radiation Monitoring

Process Radiation Monitoring Systems are provided to monitor and control radioactivity in process and effluent streams and to activate appropriate alarms and controls.

A Process Radiation Monitoring System is provided to indicate and record radiation levels associated with selected plant process streams and effluent paths leading to the environment. All effluents from the plant that are potentially radioactive are monitored.

1.2.4.8.2 Area Radiation Monitors

Area radiation monitoring systems alert plant and main control room personnel of excessive gamma radiation levels at various locations within the plant.

1.2.4.8.3 Site Environs Radiation Monitors

Radiation monitors are provided outside the plant structures to monitor radiation levels. The data obtained from these monitors are used to compute the onsite and offsite radiation levels due to the plant operations.

1.2.4.9 Shielding

Shielding is provided throughout the plant, as required, to reduce radiation levels to operating personnel and the general public within the applicable limits set forth in 10CFR20 and 10CFR50.67. It is also designed to protect certain plant components from radiation exposures that could result in unacceptable alterations of material properties or activation.

1.2.5 References

1.2.5.1 "General Electric Standard Application for Reactor Fuel", including the "United States Supplement," NEDE 24011-P-A and NEDE 24011-P-A-US (latest approved versions).

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Refer to Plant Drawing P-0001-0 in DCRMS

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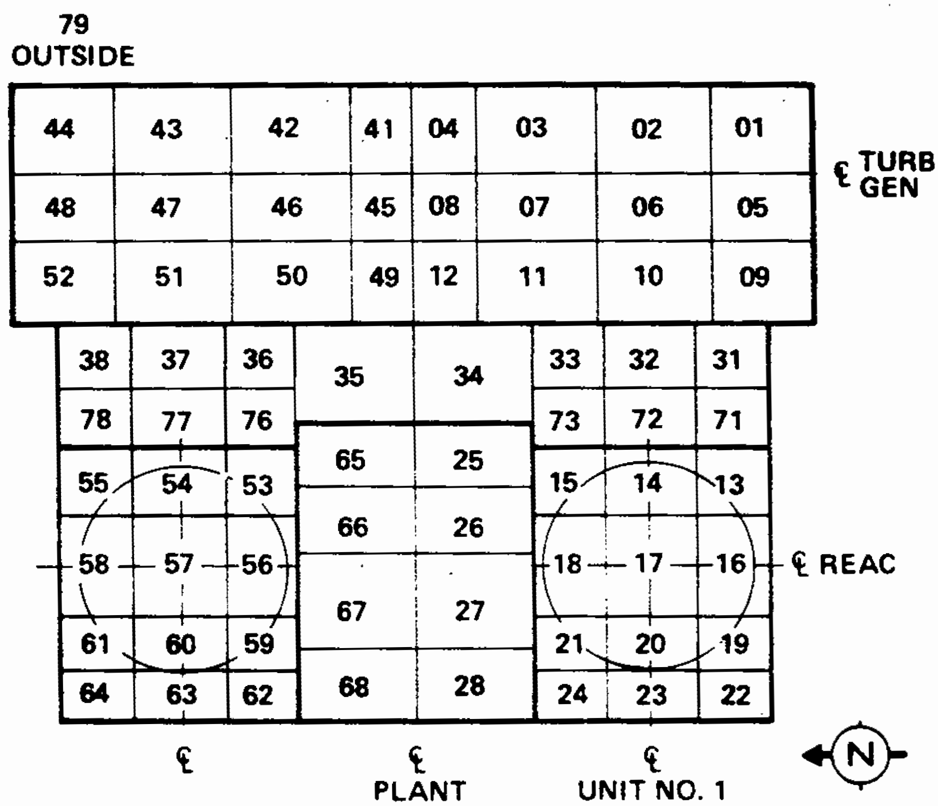

KEY PLAN

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

PLANT AREA DESIGNATIONS

UPDATED FSAR

FIGURE 1.2-44

1.3 COMPARISON TABLES

1.3.1 Comparisons with Similar Facility Designs

This section highlights the principal design features of the plant and compares its major features with those of other boiling water reactor (BWR) facilities. The design of this facility is based on proven technology obtained during the development, design, construction, and operation of BWRs of similar types. The data, performance characteristics, and other information presented here represent a current, firm design.

The following tables summarize the plant design characteristics of the Hope Creek Generating Station (HCGS), the Hatch Nuclear Plant, the Limerick Generating Station, and the Susquehanna Steam Electric Station:

Table No.	System
1.3-1	Comparison of Nuclear Steam Supply System Design Characteristics
1.3-2	Comparison of Power Conversion System Design Characteristics
1.3-3	Comparison of Engineered Safety Features and Auxiliary Systems Design Characteristics
1.3-4	Comparison of Containment Design Characteristics
1.3-5	Radioactive Waste Management Systems Design Characteristics
1.3-6	Comparison of Structural Design Characteristics
1.3-7	Comparison of Instrumentation and Electrical Systems Design Classifications

1.3.2 Comparison of Final and Preliminary Information (FSAR)

All of the significant changes that have been made in the facility design since submission of the PSAR are listed in Table 1.3-8. Each item in Table 1.3-8 is cross-referenced to the appropriate portion of the FSAR that describes the changes and the bases for them.

1.3.3 References

1.3-1 "General Electric Standard Application for Reactor Fuel," including the "United States Supplement," NEDE-24011-P-A and NEDE-24011-P-A-US, current revisions.

TABLE 1.3-1

(Historical Information)

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS[1]

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Thermal and Hydraulic Design (Section 4.4)				
Rated power, MWt	3293	2436	3293	3293
Design power, MWt (ECCS design basis)	3430	2550	3435	3439
Steam flow rate, lb/h	14.159 E6	10.03 E6	14.156 E6	13.48 E6
Core coolant flow rate, lb/h	100.0 E6	78.5 E6	100.0 E6	100.0 E6
Feedwater flow rate, lb/h	14.127 E6	10.445 E6	14.117 E6	13.574 E6
System pressure, nominal in steam dome, psia	1020	1020	1020	1020
Average power density, kW/liter	48.7	51.2	48.7	48.7
Minimum critical power ratio	1.20	(4)	1.24	1.23
Coolant enthalpy at core inlet, Btu/lb	526.1	526.2	526.1	521.8
Core maximum exit voids within assemblies	77.1	79 77.1	76.00	
Core average exit quality, % steam	14.1	12.7	14.1	13.2
Feedwater temperature, °F	419.9	387.4	420	383
Design Power Peaking Factor (Section 4.4)				
Maximum relative assembly power	1.40	1.40	1.40	1.40
Local peaking factor	1.15	1.24	(4)	1.15
Axial peaking factor	1.4	1.5	1.4	1.40
Total peaking factor	2.51	2.6	(4)	2.51

(Historical Information)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Nuclear Design (First Core) (Section 4.3)				
Reactivity with strongest control rod out, k_{eff}	<0.99	<0.99	<0.99	<0.99
Initial cycle exposure, MWD/short ton	8100	9413	9600	9600
Core Mechanical Design (Sections 4.2 and 4.6)				
Fuel Assembly (Table A.1.3-1 of Reference 1.3-1)				
Reactor Control System				
Method of variation of reactor power	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow
Number of movable control rods	185	137	185	185
Shape of movable control rods	Cruciform	Cruciform	Cruciform	Cruciform
Pitch of movable control rods	12.0	12.0	12.0	12.0
Control material in movable rods	Boron carbide (B_4C) granules compacted in stainless steel (ss) tubes	B_4C granules compacted in ss tubes	B_4C granules compacted in ss tubes	B_4C granules compacted in ss tubes
Type of CRDs	Bottom entry locking piston	Bottom entry locking piston	Bottom entry locking piston	Bottom entry locking piston
Type of temporary reactivity control for initial core	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods

(Historical Information)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
In-core Neutron Instrumentation				
Total number of (LPRM) detectors	172	124	172	172
Number of in-core LPRM penetrations	43 31	43 43		
Number of LPRM detectors per penetration	4	4	4	4
Number of SRM penetrations	4	4	4	4
Number of IRM penetrations	8	8	8	8
Total nuclear instrument penetrations	55 43	55 55		
SRMs	Range - shutdown through criticality			
	4(3)	4(3)	4(3)	4(3)
IRMs	Range - prior to criticality to low power			
	8(3)	8(3)	8(3)	8(3)
Power range monitors	Range - approximately 1% power to 125% power			
LPRMs	172	124	172	172
APRMs	6(3)	6(3)	6(3)	6(3)
Number and type of in-core neutron sources	7 Sb-Be	5 Sb-Be	7 Sb-Be	7 Sb-Be
Reactor Vessel Design (Section 5.3)				
Material	Low-alloy steel/ stainless clad	Carbon steel/ stainless clad	Carbon steel/ stainless clad	Carbon steel/ stainless clad
Design pressure, psig	1250	1250	1250	1250
Design temperature, °F	575	575	575	575
Inside diameter, ft-in.	20-11	18-2	20-11	20-11
Inside height, ft-in.	72-6.5	69-4	72-1	72-11

(Historical Information)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Minimum base metal thickness (cylindrical section), in.	6.102	5.53	6.187	6.19
Minimum cladding thickness, in.	13/64	1/8	1/8	1/8
<u>Reactor Coolant Recirculation System Design</u> (Section 5.4)				
Number of recirculation loops	2	2	2	2
Design pressure				
Inlet leg, psig	1250	1148	1250	1250
Outlet leg, psig	1500	1274	1500	1500
Design temperature, °F	575	562	575	575
Pipe diameter, in.	28	28	28	28
Pipe material, ANSI	304	304/316	316	304/316
Recirculation pump flow rate, gpm	45,200	42,200	45,200	45,200
Number of jet pumps in reactor	20	20	20	20
<u>Main Steamlines</u> (Section 5.4)				
Number of steamlines	4	4	4	4
Design pressure, psig	1250	1146	1250	1250
Design temperature, °F	575	563	575	575
Pipe diameter, in.	26	24	26	26
Pipe material	Carbon steel	Carbon steel	Carbon steel	Carbon steel

(Historical Information)

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(1) Parameters are related to rated power output for a single plant unless otherwise noted.

(2) Free-standing loaded tubes.

(3) Channels of monitors from detectors.

(4) Information not available.

(Historical Information)

COMPARISON OF POWER CONVERSION SYSTEM DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Turbine-Generator				
(Section 10.2)				
Rated power, MWe (gross)	1117.5	813.5	1138	1085
Generator speed, rpm	1800	1800	1800	1800
Rated steam flow, lb/h	14.159 E6	10.48 E6	14.85 E6	13.4 E6
Inlet pressure, psig	965	950	950	965
Steam Bypass System				
(Section 10.4.4)				
Capacity, percent design steam flow	25	25	25	25
Main Condenser				
(Section 10.4.1)				
Heat removal capacity, Btu/h	7726 E6	5720 E6	7800 E6	7890 E6
Circulating Water System				
(Section 10.4.7)				
Number of pumps	4	2	4	4
Flow rate, gpm/pump	138,000	185,000	113,000	112,000
Condensate and Feedwater System				
(Section 10.4.7)				
Design flow rate, lb/h	14.82 E6	10.096 E6	14.885 E6	13.44 E6
Number of condensate pumps	3	3	3	4
Number of condensate booster pumps	3	3	None	None
Number of feedwater pumps	3	2	3	3
Number of feedwater booster pumps	None	None	None	None
Condensate pump drive	ac power	ac power	ac power	ac power

(Historical Information)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Condensate booster pump drive	ac power	ac power	NA	NA
Feedwater pump drive	Turbine	Turbine	Turbine	Turbine

TABLE 1.3-3

COMPARISON OF ENGINEERED SAFETY FEATURES AND AUXILIARY SYSTEMS DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Emergency Core Cooling Systems				
(Systems sized on design power)				
(Section 6.3)				
LPCS Systems				
Number of loops	2	2	2	2
Flow rate, gpm (per loop)	6150 at 105 psid	4725 at 113 psid	6350 at 105 psid	6350 at 105 psid
HPCI System				
Number of loops	1	1	1	1
Flow rate, gpm	5600	4250	5600 min	5000 at 1172-165 psia
ADS				
Number of relief valves	5	7	5	6
LPCI (1)				
Number of loops	4	2	4	2
Number of pumps	4	4	4	4
Flow rate, gpm/pump	10,000 at 20 psid	9200 at 20 psid	10,000 at 20 psid	10,650 at 20 psid
Auxiliary Systems				
(Sections 5.4 and 9.1)				
RHR System				
Reactor Shutdown Cooling Mode:				
Number of loops	2	2	2	2
Number of pumps	2	4	2	2
Flow rate, gpm/pump (2)	10,000	7,700	10,000	10,000

TABLE 1.3-3 (Cont)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Duty, Btu/h/heat exchanger(3)	41.6 E6	32. E6	41.6 E6	44 E6
Number of heat exchangers	2	2	2	2
Primary containment cooling mode:				
Flow rate, gpm/heat exchanger	10,000	11,550	10,000	10,000
Standby Service Water System				
Flow rate, gpm/heat exchanger	16,500	8000	12,000	9000
Number of pumps	4	4	3	2
RCIC System				
Flow rate, gpm	600 at 150-1120 psid	400 at 150-1120 psid	625 at 1120 psid	600 at 1172-165 psia
FPCC System				
Capacity, Btu/h	12 E6	8.5 E6	11.25 E6	13.2 E6

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(1) A mode of the RHR system.
(2) Capacity during reactor flooding mode with more than one pump running.
(3) Heat exchanger duty at 20 hours following reactor shutdown.

TABLE 1.3-4

COMPARISON OF CONTAINMENT DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Primary Containment[1] (Section 6.2.1)				
Type	MK I Pressure suppression	MK I Pressure suppression	MK II pressure suppression	MK II Over and under pressure suppression
Construction	Concrete with free standing steel vessel	Concrete with free standing steel vessel	Concrete with steel liner	Concrete with steel liner
Drywell	Light bulb/ steel vessel	Light bulb/ steel vessel	Frustum of cone, upper portion	Frustum of cone, upper portion
Pressure-suppression chamber	Torus/ steel vessel	Torus/steel vessel	Cylindrical lower portion	Cylindrical lower portion
Pressure-suppression chamber internal design pressure, psig	62	56	55	53
Pressure-suppression chamber external design pressure, psi	3	2	5	5
Drywell internal design pressure, psig	62	56	55	53
Drywell external design pressure, psi	3	2	5	5
Drywell free volume, ft^3	169,000	146,010	243,580	239,600
Pressure-suppression chamber free volume, ft^3	133,500 (high water level)	112,900 (high water level)	147,670 (high water level) 159,540 (low level)	148,590 (high water level) 159,130 (low water level)
Pressure-suppression pool water volume, ft^3	122,000 (high water level)	85,112 (min)	134,600 (max) 122,120 (min)	131,550 (max) 122,410 (min)
Submergence of vent pipe below pressure pool surface, ft	3.33 (high water level)	3.67 (high water level)	12-1/4 (high water level) 10 (low water level)	11 (normal water level)

TABLE 1.3-4 (Cont)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Design temperature of drywell, °F	340	281	340	340
Design temperature of pressure-suppression chamber, °F	310	281	220	220
Downcomer vent pressure loss factor	5.51	6.18	2.18	2.5
Break area/total vent area	0.0173	0.0194	0.0159	0.016
Calculated maximum pressure after blowdown to drywell, psig	48.1	46.5	44	44
Calculated maximum pressure-suppression chamber pressure after LOCA blowdown, psig	27.5	28	30.6	29
Initial pressure-suppression pool temperature rise during LOCA blowdown, °F	41	50	43	40
Leakage rate, percent free volume/day	0.5 at 62 psig	1.2 at 59 psig	0.5	0.5
Secondary Containment (Section 6.2.3)				
Type	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, roof level release	Controlled leakage, elevated release
Construction				
Lower levels	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Upper levels	Reinforced concrete	Steel superstructure and precast concrete panels	Reinforced concrete superstructure and siding	Steel superstructure and siding
Roof	Reinforced concrete dome with steel liner	Steel sheeting and reinforced concrete slabs	Reinforced concrete	Steel decking
Internal design pressure, psig	1.00	0.25	0.25	0.25

TABLE 1.3-4 (Cont)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Design inleakage rate, percent free volume/day at 0.25 inwc (nom.)	100	100	50/100	100

(1) Where applicable, containment parameters are based on design power.

TABLE 1.3-5

RADIOACTIVE WASTE MANAGEMENT SYSTEMS DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764	Hatch 1 BWR 4 218-560
Gaseous Radwaste (Section 11.3)				
Design bases noble gases	500,000 annual average	100,000	100,000	100,000 annual average
Ci/s	at 30 min	at 30 min	at 30 min	at 30 min
Process treatment	Recombiner ambient charcoal	Recombiner and ambient charcoal delay	Ambient charcoal	Recombiner ambient charcoal
Number of beds	10	-	5	12
Design condenser inleakage, cfm	75	75	30	40
Release point-height above ground, ft	217	197	201	394
Liquid Radwaste (Section 11.2)				
Treatment of:				
1. Floor drains(1)	F,D,R,DC	F,D,R	F,D,R	F,D,R
2. Equipment drains(1)	F,D,R	F,D,R	F,D,R	F,D,R
3. Chemical drains(1)	Regenerative wastes neutralized E, distillate R, and concentrates to solid radwaste to solid radwaste Misc chemical decon wastes - neutralized E and vapor discharged. Concentrates to solid radwaste	E,D, concentrates to solid radwaste, distillater R	E, concentrates to solid radwaste, distillate R	F, DC, E, solid to radwaste

	Hope Creek BWR 4/5 251-764	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764	Hatch 1 BWR 4 218-560
4. Laundry drains	F, DC	F, D	Diluted and sent to circulating water discharge	Diluted and sent to circulating water discharge
5. Expected annual avg release, µCi (excluding tritium)	1800	(3)	(3)	2000
<u>Other Design Information</u> (Section 11.4)				
Wet solid waste processing	* * Storage and decay in phase separators. Dewatering in centrifuge. Dewatering solids to E/E. Solidify with asphalt in 55-gallon drums	Storage and decay in phase separators. Dewatered in centrifuges then solidified with cement or UF in 55-gallon drums	Storage and decay in phase separators. Dewatered in dewatering filters then solidified with cement in 55-gallon drums	Storage and decay in phase separators. Dewatering in centrifuges. Dewatering solids materials solidified with cement or UF in 55-gallon solidified with drums
Concentrated liquid waste processing	* * Crystallizer bottoms to EE. Solidify with asphalt in 55-gallon drums	Solidified with UF in 55-gallon drums	Solidified with cement in 55-gallon drums	Solidified with cement or UF in 55-gallon drums
Dry solid waste processing	Packaged with hydraulic press in wooden, steel-lined boxes	Packaged with hydraulic press in drums	Packaged with hydraulic press in boxes or drums	Packaged with hydraulic press in drums
<u>Off-gas Systems</u> (Section 11.3)				
Noble gas release rate after 30 min. delay, µCi/s	100,000 (max. expected) 500,000 (design basis)	100,000	100,000	(3)
Air flow rate (scfm)				(3)
Normal	25	75	30	(3)
Maximum	75	300 (2)	300 (2)	(3)
Diluting gas	Steam	Steam	Steam	(3)
Recombiner catalyst base	Ceramic base	Metal base	Ceramic base	(3)

* * Abandoned In Place

	Hope Creek BWR 4/5 251-764	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764	Hatch 1 BWR 4 218-560
Minimum holdup time prior to the charcoal delay, min.	10	6.3	9.6	(3)
Mass of charcoal in guard bed, lbs	200	687	1280	(3)
Delay system	Ambient charcoal	Ambient charcoal	Ambient charcoal	(3)
Number of charcoal beds/unit	10	7(Unit 1) 9(Unit 2)	5	(3)
Mass of charcoal, lb/unit	322,000	321,000	152,000	(3)
Xe adsorption coefficient, cc/g	733	733	420	(3)
Temperature/dew point, ^{o}F	65/40	65/40	65/40	(3)
Xe delay time, days	35	35	23	(3)
Collection (Section 11.2)				
	5 subsystems	4 subsystems	3 subsystems	(3)
Equipment drain	2-32,000 gal. 2-182 gpm	25,000 gal. 280 gpm	Combine w/floor	(3)
Floor drain	2-17,000 gal. 2-176 gpm	21,000 gal. 280 gpm	3-22,200 gal. 280 gpm	(3)
Chemical waste	4500 gal. 176 gpm	7500 gal. 200 gpm	11,850 gal. 20 pgm	(3)
Detergent drain collect	2000 gal. 2-25 gpm	2-1000 gal. 2-25 gpm	2-820 gal. 25 pgm	(3)
Radwaste demineralizer				
Agent	1-190 ft^3 mixed bed resin regenerable	2-85 ft^3 Podex nonregenerable	140 ft^3 mixed bed resin nonregenerable	(3)

TABLE 1.3-5 (Cont)

	Hope Creek BWR 4/5 251-764	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764	Hatch 1 BWR 4 218-560
Flow rate	180 gpm	280 gpm	200 gpm	(3)
Filter	2-precoat type 180 gpm	2-precoat type 280 gpm	2-centrifugal 200 gpm	(3)
Laundry filters	25 pairs-cartridge-type 25 gpm - can be concentrated by decon evaporator directly	1-cartridge-type 25 gpm - can be concentrated by waste evaporator feed tank	2-cartridge-type 25 gpm - can be concentrated by waste evaporator via chemical waste tank	(3)
Evaporator waste	* * 2-forced circulation 40 gpm - Distillate 40 gpm - Distillate returned to waste collection tank	2-forced circulation 20 gpm - Distillate 20 gpm - Distillate returned to waste collection tank	2-forced circulation 15-30 gpm - Distillate 15-30 gpm - Distillate returned to waste collection tank	(3)
Decon evaporator	* * Natural circulation 3 gpm - distillate to H&V vent stack	Uses waste evaporator	Uses waste evaporator	(3)

(1) Legend
- D = demineralized
- F = filtered
- E = evaporator/concentrator
- R = recycled, i.e., returned to condensate storage
- DC = discharged
- E/E = extruder-evaporator
- UF = urea formaldehyde

(2) Based on startup condition.
(3) Not available.

* * Abandoned In Place

TABLE 1.3-6

COMPARISON OF STRUCTURAL DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Seismic Design (Section 3.7)				
OBE				
Horizontal, g	0.10	0.08	0.075	0.05
Vertical, g	0.10	0.05	0.05	0.033
SSE				
Horizontal, g	0.20	0.15	0.15	0.10
Vertical, g	0.20	0.10	0.10	0.067
Wind Design (Section 3.3)				
Maximum sustained, wind speed, mph	108	105	90	80
Tornados (Section 3.3)				
Translational speed, mph	70	60	60	60
Tangential speed, mph	290	300	300	300

TABLE 1.3-7

COMPARISON OF INSTRUMENTATION AND ELECTRICAL SYSTEMS DESIGN CHARACTERISTICS

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
Transmission System (Section 8.2)				
Outgoing lines, number - rating	2 - 500-kV	5 - 230-kV	3-500-kV 2-230-kV	1-230-kV (Unit 1) 1-500-kV (Unit 2)
Normal Auxiliary AC Power (Section 8.2 and 8.3)				
Incoming lines, number - rating	2 - 500-kV and 500-kV connection to Salem switch-yard	5 - 230-kV	3-500-kV 2-230-kV	2-230-kV (Common to both units)
Station power transformer	4	2	2	1 (Unit 1) 1 (Unit 2)
Station service transformer	8	NA	NA	NA
Startup transformer	No separate startup trans-formers	2	2	2 (Common to both units)
Standby AC Power Supply (Section 8.3)				
Number of standby diesel generators	4	3	8	4 (Common to both units)
Number of 4160 V shutdown buses	4	3	8	4 per unit
Number of 480 V shutdown buses	8 load centers (Class 1E) 16 MCCS (Class 1E)	4 600 V	8	4 load centers and 8 MCCs per unit; 8 MCCs common to both units

TABLE 1.3-7 (Cont)

	Hope Creek BWR 4/5 251-764	Hatch 1 BWR 4 218-560	Limerick BWR 4/5 251-764	Susquehanna BWR 4 251-764
<u>DC Power Supply</u> (Section 8.3)				
Number of 125 V batteries	16 (6 are Class 1E) (10 are non-Class 1E)	2	4 6 125/250 V	4 per unit
Number of 250 V batteries	3 (2 are Class 1E) (1 is non-Class 1E)	2	2	2 per unit
Number of 125 V buses	12 (6 are Class 1E) (6 are non-Class 1E)	2	24	4 per unit
Number of 250 V buses	3 (2 are Class 1E) (1 is non-Class 1E)	2	12	2 load centers and 3 MCCs per unit

TABLE 1.3-8

SIGNIFICANT DESIGN CHANGES FROM PSAR TO FSAR(1)

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
General building layout changes	Core standby cooling systems were relocated outside the previously cylindrical walls in the lower Reactor Building elevations. This has resulted in a rectangular base for the lower portion of the Reactor Building.	This change was made to achieve necessary separation and space for CSCS equipment.	1.2
Unit 2	Unit 2 has been deleted, causing the following changes in the plant layout: a) The Unit 2 Turbine Building area is now used as a laydown area for Unit 1 during maintenance b) The Unit 2 Reactor Building has been abandoned c) The Unit 2 cooling tower has not been built d) The Unit 2 portion of the service water intake structure has been built but the Unit 2 bay equipment has been deleted e) Changes to the 500-kV switchyard include reducing the number of breakers to five.	This change was made because of the decreasing projected load growth.	1.2.3, 3.8.4.1.4
Mark I containment program	The containment is designed for hydrodynamic loads for a Mark I containment. A plant unique analysis report has been submitted under separate cover (letter from R.L. Mittl, PSE&G, to A. Schwencer, NRC, dated February 10, 1984.	This program is in accordance with current criteria.	3.8.2

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
Design of Reactor Building	Replaced roof, wind, and tornado loadings with a complete list of design loadings to be used.	This new list of design loadings conforms to NRC SRP 3.8.4.	3.8.4
CRD system	The return line on the control rod drive system has been capped.	This change was made in order to prevent intergranular stress corrosion cracking on the return line vessel nozzle.	3.9.4
Environmental qualification	The Hope Creek environmental qualification program for safety-related equipment is in accordance with NUREG-0588 guidelines.	This program is in agreement with current NRC guidelines.	3.11
Post-LOCA response of Reactor Building atmosphere	Maximum post-LOCA temperature was changed from 120 to 148°F.	Greater Reactor Building heat loads, plus the use of closed loop water for cooling, result in higher estimated post-LOCA building temperatures. A temperature of 148°F does not exceed the qualification limits for safety-related equipment in the Reactor Building.	3.11.1 and 6.8.1
Nuclear fuel	The arrangement of fuel rods in each fuel bundle was changed from 7 by 7 to 8 by 8.	This change increases safety margins and enhances fuel performance.	4.3
Vibration and loose parts monitoring	Instrumentation for monitoring for vibration or for the presence of loose parts in the Reactor Coolant System has been added.	This provides early detection of equipment anomalies.	4.4.6
Reactor recirculation system description	Delete the 4-inch bypass line around each recirculation pump discharge gate valve. Add a throttling circuit to the recirculation pump discharge gate valve's motor control.	Several operating BWRs have experienced cracks in this line. Its removal minimizes the potential for cracking and improves plant availability.	5.4.1

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
Main steam line header	The sizing of the header between the main steam lines has not been reduced to provide reduction in the blowdown mass loss following a main steam line break.	This change facilitates testing of the MSIVs.	10.3
RHR system	PSAR Section 15.9.4 gives three alternatives for maintaining high quality water in the torus.	Only alternatives 2 & 3 listed in the PSAR section are used. Suppression pool water and the RHR system are not treated with corrosion inhibitor.	5.4.7
Reactor isolation	PSAR Section 4.8.8 describes the RHR steam condensing mode. This mode of operation has been removed from the HCGS design.	The possibility of discharging steam to the suppression pool could have resulted in additional hydrodynamic loading on the suppression chamber.	
Main steam line tunnel	Pressure relief of the main steam tunnel is also provided through plant vents.	Plant vents have been incorporated in the main steam tunnel design to augment the pressure relief of the tunnel.	3.6.1
Post-LOCA response of Reactor Building atmosphere	The estimate of post-LOCA heat load changed from 1.8 million to 5 million Btu/h.	This reflects present estimates of building heat loads.	6.2.3
Reactor Building pressure relief	Pressure relief was changed from 2 psig to 1 psig. This includes pressure relief from the main steam line tunnel.	This permits direct venting of steam from a pipe break outside primary containment, which limits the exposure of safety-related equipment to a steam environment. Dose consequences of direct steam venting are within 10CFR50.67 guidelines.	3.6, 6.2.3, and 15.6
Containment inerting	The primary containment is inerted during plant operation.	This change is in compliance with current NRC requirements.	6.2.5

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
HPCI system	Instead of injecting 5600 gpm through the core spray sparger, 2600 gpm is diverted to the feedwater sparger.	This change deletes the requirements for a selective ATWS runback circuit.	6.3
Nuclear system pressure relief system	The PSAR states that there are eleven relief valves and four safety valves mounted on the main steam lines. The pressure relief system has fourteen safety/relief valves instead.	This is a more efficient design.	6.3
Preoperational test program - HPCI system	A full flow functional test is performed to and from the condensate storage tank only and is not alternated with the suppression pool.	The only HPCI return line to the suppression pool is the minimum bypass line. This does not provide sufficient capacity for a full flow functional test.	6.3.2
RBVS	The Reactor Building ventilation exhaust is set to establish a negative building pressure during normal operation by modulating exhaust fan damper position.	Results of calculations of the reactor building post-LOCA response show this to be an acceptable design.	6.4
Reactor Building FRVS	Changed the number of FRVS recirculation units from three 50 percent to six 25 percent units.	This change was made to meet the requirements of Regulatory Guide 1.52, i.e., the volumetric air flow rate of a single cleanup train should be limited to approximately 30,000 cfm. Since the total recirculation flow is 120,000 cfm, having three 50 percent units (60,000 cfm each) would exceed this limitation.	6.8
Post-accident monitoring	Extensive additions have been made to post-accident instrumentation.	Additional instrumentation is in agreement with Regulatory Guide 1.97, Revision 2.	7.5

TABLE 1.3-8 (Cont)

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
	Emergency response facilities now provide post-accident display information.	Emergency response facilities were added in agreement with NUREG-0696 requirements.	
	A post-accident sampling station that provides grab samples has been added.	A post-accident sampling system was added in agreement with NUREG-0737 requirements.	9.3.2
125 V and 250 V dc power systems	Vital loads have been isolated from nonvital loads.	This change was made to comply with Regulatory Guide 1.32	8.3
125 V and 250 V dc power systems	The vital ac source to the charger for the vital 250 V batteries from 230 V to 480 V have been changed. The associated circuit breakers have also been changed from nonautomatic to automatic.	Higher voltage and automatic circuit breakers were selected to improve system efficiency and to increase system protection.	8.3
Standby diesel generators	The diesel generators have been purchased with a continuous rating of 4430 kW each.	The higher continuous rating is conservative and is adequate for the design loads.	8.3
Standby diesel generators	The station standby diesel generator system consists of four automatically starting diesel generators that are dedicated to supply power to the four vital buses in the one unit if offsite power is unavailable.	This change reflects agreement with Regulatory Guide 1.32.	8.3
Fuel pools and fuel access	Deleted design that the truck receiving bay floor is designed to withstand a spent fuel cask drop from the operating deck.	It is not feasible to design the truck/railroad receiving bay floor to withstand the impact of a spent fuel cask dropped from the refueling floor (design features based on a 125-ton cask). Therefore, special design features based on NUREG-0612 are incorporated in the design of the crane to exclude consideration of cask drop from structural design.	9.1.2

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
High density fuel racks	A high density fuel rack design is now used.	This reflects state-of-the-art design allowing maximum fuel storage.	9.1.2
Reactor Building polar crane	The PSAR states that the polar crane rails are removed in the vicinity of the fuel pool to prevent movement of the crane over the pool. Instead, the crane rail is not removed, and mechanical stops and limit switches are used to prevent the 150-ton hook from traveling above the fuel pool. A 10-ton hook is allowed to travel above the fuel pool.	With the present arrangement of refueling floor, removal of the crane rails in the vicinity of the fuel pool would also prevent crane access to the dryer and separator storage pool.	9.1.5
SSWS, SACS, and RACS	Modified cooling water systems to place all plant cooling loads on intermediate loops. The SSWS consists of two essential supply trains that supply water to the associated SACS, and a single nonessential train that supplies water to the RACS.	This increases the plant reliability and safety by using fresh water to cool all plant equipment previously cooled directly with service water (Delaware River water). The intermediate loops also provide an additional barrier for containment of radioactive contaminated water.	9.2.1, 9.2.2, and 9.2.8
Breathing Air System	The Hope Creek plant now has provisions for a breathing air supply.	This provides workers with a filtered air supply while working in areas of potential airborne contamination and thus minimizes occupational exposures.	9.5.10
Standby liquid control	The system is now capable of supplying a 86 gpm flow.	Mitigation of ATWS events	9.3.5
RBVS	Station service water piping no longer penetrates the primary containment.	The drywell cooling units are now cooled by either chilled water or RACS water, both of which are closed loop systems.	9.4.2
Service Area, Heating, Cooling and Ventilating systems	Multizone fans are deleted and pre-filters and after-filters are added to the control room air conditioning system.	Multizone fans are not required in the control area and pre-filters and after-filters provide higher efficiency cleanup.	9.4.3

TABLE 1.3-8 (Cont)

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
Radwaste Area Heating, Cooling, and Ventilating System	An additional FSAR section, not included in the PSAR, describes the heating, ventilating, and air conditioning for the Auxiliary Building service area.	Since the Auxiliary Building service area HVAC is to be a distinct system serving certain areas that are separate from the radwaste area and other Auxiliary Building areas, a new FSAR section describing the service area HVAC system is necessary.	9.4.3
FPS	A motor driven fire pump was added to the system. The water source has been changed from Delaware River water to two 300,000-gallon water storage tanks to be filled from the site well.	The original diesel-engine-driven fire pump now serves as a standby fire pump. Delaware River water quality in the vicinity of Hope Creek is not suitable for fire protection.	9.5.1
CWS	The 144-inch turbine building isolation valves were deleted.	They were an operational feature later deemed undesirable and unimportant to safety.	10.4.5
CWS	Condenser bypass line was eliminated.	Not required for system operation reliability or safety.	10.4.5
Cooling towers	The number of cooling towers has been changed to one instead of two.	This change was made because of the new facility layout when the original site was changed to Artificial Island.	10.4.5
Power conversion system	Changed number of feedwater pumps from two to three.	This change permits a higher plant generating capacity upon loss of a single feedwater pump.	10.4.7
GRS	The type of off-gas system has been changed from a cryogenic to an ambient charcoal system.	The charcoal system is a simpler system. It improves the reliability of the system and the plant availability. In addition, it requires less maintenance and is able to better meet the goals of Regulatory Guide 8.9.	11.3

Item	Change	Reason for Change	FSAR Section in Which Subject is Discussed
Station shielding design surveillance and testing	The FSAR states that the purpose of the initial shield test is to detect any shielding inadequacies (calculational and/or radiation streaming or shine) rather than to detect cracks or voids as indicated in the PSAR.	Regular area radiation surveys would not detect cracks or voids, and methods to do so are very lengthy and expensive and require specialized instrumentation and sources.	12.3.2
Station shielding design turbine building	The moisture separators are located above the turbine deck, not below it.	The disadvantages of putting moisture separators below the operating floor: a. Longer main steam runs are required b. Congestion is increased below the operating floor c. The moisture separators would no longer be self-draining to heater no. 5 d. The moisture separators would be more difficult to install and support. Adequate shielding can be provided above the operating floor to reduce offsite doses from N^{16} to acceptable levels.	12.3.2

(1) Changes listed are only those that have occurred since the last PSAR amendment.
The NRC has been notified of all other major design changes through amendments to the PSAR.

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

1.4.1 Applicant

Public Service Electric and Gas Company (PSE&G) is the applicant for the utilization facility license and will operate the plant upon completion. Prime contractors and principal consultants are identified in Sections 1.4.2 through 1.4.5.

The applicant has been responsible for the design and currently operates seven multiunit fossil fuel power plants and one two unit nuclear power plant. Additionally, several combustion turbine driven generator installations have also been designed, constructed, and are currently being operated by the applicant.

The applicant also has an ownership interest in one pumped storage plant, two operating fossil fuel plants, and a two unit operating nuclear power plant. These plants provide capacity and energy to the applicant's system, but are not operated by the applicant.

These facilities, which had a net capacity of 8995 MWe at the end of 1982, constitute the applicant's electric generating system.

The applicant has been active in the development of atomic energy for generation of electricity for over 30 years. In 1952, it became a charter member of the Dow Chemical-Detroit Edison Nuclear Power Development Project, which subsequently became Atomic Power Development Associates, Inc. (APDA). This organization designed and developed a fast breeder power reactor for the Atomic Energy Commission's Power Demonstration Program. In 1957, the applicant began consultant services for the Princeton University Plasma Physics Laboratory, and it continues to work closely with the laboratory in the research and development of fusion technology. In 1972, the applicant pioneered plans for the world's first offshore floating nuclear generating station. The applicant has contributed manpower and financial support to numerous other research and development projects including the High Temperature Reactor

Development Associates, Inc, Fast Breeder Reactor Research, the Liquid Metal Fast Breeder Reactor (LMFBR) Breeder Reactor Corp, the Direct Cycle High Temperature Gas Cooled Reactor, the Westinghouse Fusion-Fission Hybrid Study, and Nuclear Reactor and Plant Engineering Research.

The applicant's engineers have participated in nuclear assignments ranging from the classroom to the nation's leading nuclear laboratories and most advanced reactor projects. The applicant sponsored engineers in nuclear training programs such as the Oak Ridge School of Reactor Technology, and in extended assignments at facilities such as the Oak Ridge National Laboratory, the Argonne National Laboratory, the National Reactor Testing Station, the Knolls Atomic Power Laboratory, the General Atomic Division of General Dynamics Corporation, and the Atomic Power Development Associates. Its engineers have participated in such nuclear projects as the Experimental Boiling Water Reactor, the Materials Testing Reactor, the Engineering Test Reactor, the Seawolf, the Peach Bottom Atomic Power Station, the Empire State Atomic Development Associates High-Temperature Gas-Cooled Reactor Program, and the Enrico Fermi Atomic Power Station.

The applicant's engineers were extensively involved in the design, construction, startup, operation, and maintenance of the Salem Generating Station Units 1 and 2, each unit consisting of a pressurized water reactor (PWR).

1.4.2 Architect/Engineer and Constructor

The applicant has retained Bechtel Power Corporation and Bechtel Construction, Inc. to provide architectural, engineering, construction, and startup assistance services for Hope Creek Generating Station (HCGS). The change in corporate entity from

Bechtel Power Corporation to Bechtel Construction Inc. for construction activities, was implemented on May 21, 1984. In addition, Bechtel Power Corporation is responsible for procurement of equipment other than the Nuclear Steam Supply System (NSSS), turbine generator, and certain other major components that have been purchased by the applicant. Bechtel Power Corporation has been continuously engaged in engineering and construction activities since 1898. A review of recent tabulations of nuclear units in the continental United States that are planned, under construction, or in operation, indicates that Bechtel is responsible for the engineering design of approximately 60 of these units and for the construction of about 40 units. Bechtel Power Corporation and Bechtel Construction Inc., are, therefore, eminently qualified to provide the required services for station design, equipment procurement, construction, and startup assistance.

1.4.3 Nuclear Steam Supply System Supplier

General Electric Company (GE) has the contract to design, fabricate, and deliver the boiling water type NSSS and nuclear fuel for HCGS, as well as to provide technical direction for installation and startup of this system. GE has been engaged in the development, design, construction, and operation of BWRs since 1955. A review of recent tabulations of nuclear units in the United States that are planned, under construction, or in operation reveals that approximately 65 of these units employ General Electric BWRs. Thus, General Electric has substantial experience, knowledge, and capability to design, manufacture, and furnish technical assistance for the installation and startup of the HCGS NSSS.

1.4.4 Turbine Generator Supplier

GE has the contract to design, fabricate, and deliver the turbine generator for HCGS, as well as to provide technical assistance for installation and startup of this equipment. GE has a long history in the application of turbine generators to nuclear power stations dating back to 1955. Over 100 of the nuclear units planned, under construction, or in operation in the United States employ General Electric turbine generators. General Electric is, therefore, well qualified to design, fabricate, and deliver the turbine generator for HCGS, and to provide technical assistance for the installation and startup of this equipment.

1.4.5 Consultants

PSE&G has engaged consultants to provide information and recommendations in a number of specialized fields. Principal consultants include:

Consultant	Area of Contribution
Dames & Moore	Geology, seismology, ground water, hydrology
EDS Nuclear	Seismic analysis
Kibbe & Associates	Nuclear fuel supply
Meteorological Evaluation Services, Inc	Meteorology
Nuclear Exchange Corp	Nuclear fuel supply
Nutech	Mark I containment plant unique analysis
Pickard, Lowe, & Garrick	Cooling tower studies
S.M. Stoller Corp	Nuclear fuel supply
Separative Work Unit Corp	Nuclear fuel supply
Southwest Research Institute	Inservice inspection

A.D. Little	River traffic studies
NUS Corporation	Safety and risk assessment

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

1.5.1 Current Development Programs

1.5.1.1 Instrumentation for Vibration

Vibration testing for reactor internals is performed on all General Electric (GE) boiling water reactor (BWR) plants. At the time of issue of Regulatory Guide 1.20, test programs for compliance were instituted. The first BWR 4 plant, Browns Ferry 1, is considered a prototype design and is instrumented and subjected to both cold and hot two-phase flow testing to demonstrate that flow induced vibrations, similar to those expected during operation, do not cause damage. Subsequent plants that have internals similar to those of the prototype are tested in compliance to the requirements of Regulatory Guide 1.20 to confirm the adequacy of the design with respect to vibration. Further discussion is presented in Section 3.9.2 and in NEDO-24057A, Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants, Reference 1.5-1.

1.5.1.2 Core Spray Distribution

The design basis for core spray distribution for BWR 4 plants has been described in References 1.5-2 and 1.5-3. Other loss-of-coolant accident (LOCA) programs, jointly sponsored by GE/NRC/EPRI have shown that the core spray systems' introduction of core spray water into the upper plenum results in a pool of water in the upper plenum. This provides a water downflow into all of the fuel bundles. When this water inventory in the upper plenum subcools, the countercurrent flow limiting at the upper tieplate breaks down; thus, the water flows through the core and refloods the core at an earlier time than currently calculated. Fuel bundle heat transfer, consistent with system performance during the time from rated core spray to core reflood, has been shown to exceed the values allowed by Reference 1.5-3. This behavior has been verified by overseas testing and reported at the "Ninth Water Reactor Safety Research Information Meeting," October 26 through 30, 1981.

1.5.1.3 Core Spray and Core Flooding Heat Transfer Effectiveness

Due to the incorporation of an 8x8 fuel rod array with unheated water rods, tests have been conducted to demonstrate the effectiveness of the Emergency Core Cooling System (ECCS) in the new geometry.

These tests are regarded as confirmatory only, since the geometry change is very slight, and the water rods provide an additional heat sink on the inside of the bundle, improving heat transfer effectiveness.

There are two distinct programs involving the core spray. One program is discussed in Section 1.5.1.2. The other program concerns the testing of core spray and core flooding heat transfer effectiveness. The results of testing with stainless steel cladding were reported in Reference 1.5-4. The results of testing using Zircaloy cladding were reported in Reference 1.5-5.

1.5.1.4 Verification of Pressure Suppression Design

The initial Mark I pressure suppression tests were performed from 1958 through 1962 to demonstrate the viability of the pressure-suppression concept for reactor containment design. The tests were designed to simulate LOCAs with breaks in piping sized up to approximately twice the cross-sectional break area of the design-basis LOCA.

In 1977, testing was initiated at the quarter scale test facility (QSTF). The QSTF was designed so that the suppression-chamber section width, drywell volume, downcomer system configuration, vent system resistance, vent header deflector, and other test conditions could be varied on a plant specific basis. The data obtained from the QSTF plant unique tests serve as the principal source for the pool swell load specifications. The scaling relationships for the pool swell tests were developed based on the method of similitude. Independent research studies, performed for the NRC by the

Massachusetts Institute of Technology, the Lawrence Livermore Laboratory, and the University of California at Los Angeles, have confirmed these pool swell scaling relationships.

In 1978, tests were initiated at the full scale test facility (FSTF). The FSTF was a full scale, 22.5° sector of a typical Mark I suppression chamber connected to simulated drywell and pressure vessel volumes. The tests simulated blowdowns over a range from small breaks to the design basis accident (DBA). The principal design parameters, e.g., vent area to pool area ratio, and distance of the downcomer exit to the suppression chamber shell, were selected to produce conservative data from which the loads could be derived. The condensation oscillation and chugging design loads are based on the results of the FSTF tests.

1.5.1.5 Critical Heat Flux Testing

A program for critical heat flux testing was established similar to that described in Reference 1.5-6. Since that time, however, a new analysis has been performed and the GE BWR Thermal Analysis Basis (GETAB) program, Reference 1.5-7, initiated. The results of that analysis and related testing are described in Reference 1.5-7.

1.5.2 References

1.5-1 General Electric, "Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants," NEDO-24057A, November 1977.

1.5-2 General Electric, "BWR Core Spray Distribution," NEDO 10846, April 1973.

1.5-3 General Electric, "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K - Effect of Steam Environment on BWR Core Spray Distribution," NEDE 20566-P-A, Volume 3, September 1986.

1.5-4 General Electric, "Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness," Licensing Topical Report, NEDO-10801, March 1973.

1.5-5 General Electric, "Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8X8 Simulated BWR Fuel Bundle," Licensing Topical Report, NEDO-20231, December 1973.

1.5-6 "Design Basis for Critical Heat Flux Condition in Boiling Water Reactors," APED-5286, September 1966.

1.5-7 General Electric, "General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application," Licensing Topical Report, NEDO-10958-A, January 1977.

1.6 MATERIAL INCORPORATED BY REFERENCE

The following is a tabulation of topical reports and other documents referenced in this FSAR.

Report Number	Title	Referenced in FSAR Section
GENERAL ELECTRIC COMPANY REPORTS:		
APED-4827	Maximum Two-Phase Blowdown from Pipes, April 1965.	6.2
APED-5286	Design Basis for Critical Heat Flux Condition in BWRs, September 1966.	1.5
APED-5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors, March 1968.	5.4
APED-5460	Design and Performance of General Electric BWR Jet Pumps, July 1968.	3.9
APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A, November 1967.	4.6
APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves, March 1969.	5.4
APED-5756	Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor, March 1969.	15.4, 15.7

Report Number	Title	Referenced in FSAR Section
GEAP-5620	Failure Behavior in ASTM A1063 Pipes Containing Axial Through-Wall Flows, April 1968	5.2
NEDC-32410P-A	Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Plus Option III Stability Trip – Licensing Topical Report	
NEDC-33075P-A	Licensing Topical Report GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density	7.6
NEDC-33153P	“SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis for Hope Creek Generating Station”	6.3
NEDE-10313	PDA - Pipe Dynamic Analysis Program for Pipe Rupture Movement (Proprietary Filing).	3.6
NEDE-10958A	General Electric Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application, January 1977	4.4
NEDE-20566-P-A	General Electric Company Model for Loss-of-Coolant Accident Analysis in Accordance with 10CFR50 Appendix K, September 1986.	1.5, 3.9, 6.3
NEDE-20944-P	BWR/4 and BWR/5 Fuel Design, Proprietary Versions, October 1976.	
NEDE-20944-P-1	BWR/4 and BWR/5 Fuel Design, Amendment 1, (only BWR/4&5,) January 1977.	4.2 4.3
NEDE-21354-P	BWR Fuel Channel Mechanical Design and Deflection, September 1976.	3.9
NEDE-23014	HEX O1 User's Manual, July 1976.	15.2
NEDE-24011-P-A	General Electric Standard Application for Reactor Fuel, latest revision	1.2, 1.3, 4.1, 4.2, 4,3, 4,4, 6.3, 15.0, 15.3, 15.4

Report Number	Title	Referenced in FSAR Section
NEDE-24011-P-A-US	General Electric Standard Application for Reactor Fuel, United States Supplement, Latest revision	1.2, 1.3 4.1, 4.2, 4.3, 4.4, 6.3, 15.0 15.3, 15.4
NEDE-24222	Assessment of BWR Mitigation of ATWS (NUREG-0460 Alternate No. 3), Volume 1, May 1979; Volume 2, December 1979.	15.8
NEDE-24834	Hanford 2 Crimped CRD Hydraulic Withdrawal Lines, (Proprietary).	3.6
NEDO-10029	An Analytical Study on Brittle Fracture of GE-BWR Vessel Subjected to the Design Basis Accident, July 1969.	5.3
NEDO-10173	Current State of Knowledge, High Performance BWR Zircaloy-clad UO3[16]2 Fuel, May 1970.	11.1
NEDO-10320	The General Electric Pressure Suppression Containment Analytical Model, April 1971; Supplement 1, May 1971.	6.2
NEDO-10349	Analysis of Anticipated Transients Without Scram, March 1971.	15.8
NEDO-10505	Experience with BWR Fuel Through September 1971, May 1972.	11.1

Report Number	Title	Referenced in FSAR Section
NEDO-10585	Behavior of Iodine in Reactor Water During Plant Shutdown and Startup, August 1972.	15.6
NEDO-10602	Testing of Improved Jet Pumps for the BWR/6 Nuclear System, June 1972.	3.9
NEDO-10739	Methods for Calculating Safe Test Intervals And Allowable Repair Times for Engineered Safeguard Systems, January 1973.	6.3, 15.9
NEDO-10801	Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness, March 1973.	1.5
NEDO-10802-A	Analytical Methods of Plant Transient Evaluations for General Electric Boiling Water Reactor, December 1986.	4.1, 15.1
NEDO-10846	BWR Core Spray Distribution, April 1973.	1.5
NEDO-10871	Technical Derivation of BWR 1971 Design Basis Radioactive Material Source Terms, March 1975.	11.1
NEDO-10899	Chloride Control in BWR Coolants, June 1973.	5.2
NEDO-10958-A	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application, January 1977.	1.5, 4.4

Report Number	Title	Referenced in FSAR Section
NEDO-11209-0A	Nuclear Energy Business Operations Boiling Water Reactor Quality Assurance Program Description, Latest NRC-Accepted Revision	1.8
NEDO-12037	Summary of X-Ray and Gamma-Ray Energy and Intensity Data, January 1970.	12.3
NEDO-20231	Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy Clad, 8X8 Simulated BWR Fuel Bundle, December 1973.	1.5
NEDO-20626	Studies of BWR Designs for Mitigation of Anticipated Transients Without Scrams, October 1974.	15.8
NEDO-20651	BWR Radiation Effects Design Curve, March 1975.	5.3
NEDO-20922	Experience With BWR Fuel Through September 1974, June 1975.	11.1
NEDO-21142	Realistic Accident Analysis for General Electric Boiling Water Reactor; The RELAC Code and User's Guide, January 1978.	15.4, 15.6, 15.7

Report Number	Title	Referenced in FSAR Section
NEDO-21143	Conservative Radiological Accident Evaluation The CONAC01 Code, March 1976.	15.4, 15.6, 15.7
NEDO-21159	Airborne Release from BWRs for Environmental Impact Evaluations, March 1976.	11.1, 12.3
NEDO-21159-2	Airborne Releases from BWRs for Environmental Impact Evaluations, 1977.	12.3
NEDO-21506	Stability and Dynamic Performance of the General Electric Boiling Water Reactor, January 1977.	4.1
NEDO-21660	Experience with BWR Fuel through December 1976, July 1977.	11.1
NEDO-21778-A	Transient Pressure Rises Affecting Fracture Toughness Requirements for BWRs, December 1978.	5.3
NEDO-21821-2	Boiling Water Reactor Feedwater Nozzle/Sparger Final Report (Nonproprietary), August 1979.	5.3
NEDO-24057-A	Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants, November 1977.	1.5, 3.9
NEDO-24154-A	Qualification of the One-Dimensional Core Transient Model For BWR, August 1986.	4.1, 5.2, 15.1

Report Number	Title	Referenced in FSAR Section
NEDO-24988	Analysis of Generic BWR Safety/ Relief Valve Operability Test Results, October 1981.	5.2
NEDO-31960	BWR Owners' Group Long Term Stability Solutions Licensing Methodology, June 1991	7.6
NEDO-31960 Supplement 1	BWR Owners' Group Long Term Stability Solutions Licensing Methodology, March 1992	7.6

OTHER REFERENCED REPORTS

AEEW-R-705	An Investigation Into the Effects of Crud Deposits on Surface Temperature, Dry-Out, and Pressure Drop, with Forced Convection Boiling of Water at 69 Bar in an Annular Test Section, 1971.	4.4
	(Historical Information)	
AI-75-2	Thermal Hydrogen Recombiner System for Water-Cooled Reactors, Revision 2, July 1975.	6.2
AI-77-55	Thermal Hydrogen Recombiner System for Mark I and II Boiling Water Reactors, September 1977.	6.2
ANL-6948	Condensation of Metal Vapors: Mercury and the Kinetic Theory of Condensation, October 1964.	6.2
BHR/DER 70-1	Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor, March 1970.	11.1

Report Number	Title	Referenced in FSAR Section
CF 59-6-47 (ORNL)	Removal of Fission Product Gases from Reactor Offgas Streams by Adsorption, 1959.	11.3
EPRI NP-495	Sources of Radioiodine at Boiling Water Reactors, February 1978.	12.2
ORNL-3041	SDC, A Shielding-Design Calculation for Fuel-Handling Facilities, March 1966.	12.3
ORNL-4585	Morse - A Multigroup Neutron and Gamma-Ray Monte Carlo Transport Code, September 1973.	12.3
ORNL-4628	Origen - The ORNL Generation and Depletion Code, May 1973.	12.3
ORNL-4932	Radioactive Atoms Supplement 1, August 1973.	12.3
ORNC-NSIC-23	Potential Metal Water Reaction in Light Water Cooled Power Reactors, August 1968.	6.2
ORNL-RSIC-10	A Survey of Empirical Functions Used to Fit Gamma Ray Buildup Factor, February 1966.	12.3
ORNL-RSIC-21	Neutron and Gamma Ray Albedos, February 1968.	12.3
ORNL-TM-4280	The DOT 3 Two Dimensional Discrete Ordinates Transport Code, September 1973.	12.3

Report Number	Title	Referenced in FSAR Section
	(Historical Information)	
FC-4290	Hydrogen Evolution from Zinc Corrosion under Simulated Loss-of-Coolant Accident Conditions, August 1976.	6.2
WASH-1258	Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion as Low as Practicable for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents.	11.3
WCAP-8776	Corrosion Study for Determining Hydrogen Generation from Aluminum and Zinc During Post-Accident Conditions, 1976.	6.2
WAPD-TM-918	Thermal and Hydraulic Effects of Crud Deposited on Electrically Heated Rod Bundles, September 1970.	4.4

BECHTEL POWER CORPORATION REPORTS

BC-TOP-4A	Seismic Analyses of Structures and Equipment for Nuclear Power Plants, Revision 3, November 1974.	3.7
BC-TOP-3A	Tornado and Extreme Wind Design Criteria for Nuclear Power Plants, Revision 3, August 1974.	3.3
BC-TOP-9A	Design of Structures for Missile Impact, Revision 2, September 1974.	3.5

Report Number	Title	Referenced in FSAR Section
BN-TOP-1	Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants, November 1972.	6.2
BN-TOP-2	Design for Pipe Break Effects, Revision 2, May 1974.	3.6, 3.8
BN-TOP-4	Subcompartment Pressure Analyses Revision 0, July 1976.	3.6
BP-TOP-1	Seismic Analysis Piping System, Revision 3, January 1976.	3.7
ABB COMBUSTION ENGINEERING REPORTS:		
CENPD-300-P-A	Reference Safety Report for Boiling Water Reactor Reload Fuel, July 1996	4.1, 4.2, 4.3, 4.4
CENPD-287-P-A	Fuel Assembly Mechanical Design Methodology for Boiling Water Reactors	3.9, 4.2
CENPD-288-P-A	ABB Seismic/LOCA Evaluation Methodology for Boiling Water Reactor Fuel	3.9
WCAP-15942-P-A	Fuel Assembly Mechanical Design Methodology for Boiling Water Reactors, Supplement 1 to CENP-287	4.2

1.7 DRAWINGS AND OTHER DETAILED INFORMATION

Table 1.7-1 provides a listing of electrical drawings used in the plant design.

Table 1.7-2 provides a listing of piping and instrumentation diagrams (P&IDs) used in the plant design.

Table 1.7-3 provides a listing of control and instrumentation drawings used in the plant design.

It should be noted that the information presented in these tables is considered current through FSAR Amendment 15. However, the Figures contained in the UFSAR have been deleted and replaced with references to the appropriate Plant Drawings or Vendor Technical Document.

TABLE 1.7-1

ELECTRICAL DRAWINGS

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0001-0	Single line Diagram, Station	8.3-1	6	02/11/85
E-0002-1, Sh 1	Single line Meter & Relay Diagram, Power System	8.3-2 Sh 1	7	12/17/85
E-0002-1, Sh 2	Single line Meter & Relay Diagram, Power System	8.3-2 Sh 2	4	12/17/85
E-0003-1	Single line Meter & Relay Diagram Generator, Main Transformer	8.3-3	5	09/30/85
E-0004-1	Single line Meter and Relay Diagram, 7.2 kV Station Power System	8.3-4	5	01/24/85
E-0005-0	Single line Meter & Relay Diagram, 4.16 kV Station Power System		4	10/06/83
E-0005-1, Sh 1	Single line Meter & Relay Diagram, 4.16 kV Station Power System		5	03/13/85
E-0005-1, Sh 2	Single line Meter & Relay Diagram, 4.16 kV Station Power System		3	03/13/85
E-0006-1, Sh 1	Single line Meter & Relay Diagram, 4.16 kV Class 1E Power System	8.3-5 Sh 1	4	03/13/85
E-0006-1, Sh 2	Single line Meter & Relay Diagram, 4.16 kV Class 1E Power System	8.3-5 Sh 2	4	03/13/85
E-0007-1	Single line Diagram Synchronizing	8.3-6	5	08/02/85
E-0008-1	Single line Meter & Relay Diagram, Diesel Generators	8.3-7	2	08/02/85
E-0009-1, Sh 1	Single line Meter & Relay Diagram, 125 V dc System	8.3-8 Sh 1	7	11/22/85
E-0009-1, Sh 2	Single line Meter & Relay Diagram, 125 V dc System	8.3-8 Sh 2	8	11/22/85
E-0009-1, Sh 3	Single line Meter & Relay Diagram, 125 V dc System	8.3-8 Sh 3	8	11/22/85
E-0009-1, Sh 4	Single line Meter & Relay Diagram, 125 V dc System	8.3-8 Sh 4	4	11/22/85
E-0009-1, Sh 5	Single line Meter & Relay Diagram, 125 V dc System	8.3-8 Sh 5	4	11/22/85
E-0010-0	Single line Meter & Relay Diagram, ±24 V dc System	8.3-9	3	01/31/83
E-0011-1, Sh 1	Single line Meter & Relay Diagram, 250 V dc System	8.3-10 Sh 1	7	12/02/85
E-0011-1, Sh 2	Single line Meter & Relay Diagram, 250 V dc System	8.3-10 Sh 2	6	12/02/85
E-0012-1, Sh 1	Single line Meter & Relay Diagram, 120 V ac Instrumentation & Miscellaneous Sys	8.3-11 Sh 1	7	11/03/86

TABLE 1.7-1

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0012-1, Sh 2	Single line Meter & Relay Diagram, 120 V ac Instrumentation Miscellaneous Sys	8.3-11 Sh 2	9	01/03/86
E-0012-1, Sh 3	Single line Meter & Relay Diagram, 120 V ac Instrumentation & Miscellaneous Sys	8.3-11 Sh 3	8	07/25/85
E-0012-1, Sh 4	Single line Meter & Relay Diagram, 120 V ac Instrumentation & Miscellaneous Sys	8.3-11 Sh 4	4	01/03/86
E-0012-1, Sh 5	Single line Meter & Relay Diagram, 120 V ac Instrumentation & Miscellaneous Sys	8.3-11 Sh 5	8	10/21/85
E-0018-1, Sh 1	Single line Meter & Relay Diagram, 480 V, Class 1E Unit Substation 10B410, 420, 430, 440, 450, 460, 470, 480	8.3-12 Sh 1	8	09/19/85
E-0018-1, Sh 2	Single line Meter & Relay Diagram, 480 V Class 1E Unit Substation 10B410, 420, 430, 440, 450, 460, 470, 480	8.3-12 Sh 2	8	09/19/85
E-0018-1, Sh 3	Single line Meter & Relay Diagram, 480 V Auxiliary Breaker Centers 10B415, 426, 437, 448	8.3-12 Sh 3	5	06/11/85
E-0019-1, Sh 1	480 V Motor Control Center (MCC) Tabulation, Class 1E, Auxiliary Building, Diesel Generator (DG) Area 10B411, 10B421, 10B431, & 10B441		6	08/21/85
E-0019-1, Sh 2	480 V MCC Tabulation Class 1E, Auxiliary Building, DG Areas 10B411, 421, 431, 441		6	08/21/85
E-0020-1, Sh 1	480 V MCC Tabulation Class 1E Auxiliary Building DG Area 10B451, 461, 471, 481		7	02/25/85
E-0020-1, Sh 2	480 V MCC Tabulation Class 1E Auxiliary Building DG Area 10B451, 461, 471, 481		8	11/12/85
E-0021-1, Sh 1	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	08/21/85
E-0021-1, Sh 2	580 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	08/21/85
E-0021-1, Sh 3	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	06/27/85
E-0021-1, Sh 4	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	10/11/85
E-0021-1, Sh 5	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	05/31/85
E-0021-1, Sh 6	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B212, 222, 232, 242		9	08/16/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0022-1, Sh 1	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B553, 563, 573, 583		6	06/28/85
E-0022-1, Sh 2	480 V MCC Tabulation Class 1E MCC-Reactor Area 10B553, 563, 573, 583		4	06/28/85
E-0023-1, Sh 3	480 V MCC Tabulation 10B252, 10B262, 10B272, 10B282, 10B313, 10B323, and 00B474 - Reac, R/W & Control Area		10	11/12/85
E-0036-1	Schematic Phasing Diagram, 4.16 kV & 480 V Class 1E System		1	11/04/84
E-0040-1	Schematic Meter & Relay Diagram, Synchronizing		6	08/23/85
E-0046-1	Schematic Meter & Relay Diagram, 4.16 kV Class 1E Station Power System Switchgears 10A401 & 10A403		6	09/06/84
E-0047-1	Schematic Meter & Relay Diagram, 4.16 kV Class 1E Station Power System Switchgears 10A402, 10A404		6	09/06/84
E-0048-1	Schematic Meter & Relay Diagram, Diesel Generators		10	07/26/85
E-0068-0	Electrical Schematic Diagram (ESD), Class 1E-4.16 kV Station System Switchgear, Main Circuit Breaker (1)52-40108		9	05/07/85
E-0069-0	ESD, Class 1E 4.16 kV Station Power Switchgear, Main Circuit Breaker (1)52-40108		7	05/07/85
E-0070-0	ESD, Class 1E 4.16 kV Station Power Switchgear Main Circuit Breaker (1)52-40201		7	05/07/85
E-0071-0	ESD, Class 1E 4.16 kV Station Power Switchgear Main Circuit Breaker (1)52-40208		7	05/07/85
E-0072-0	ESD, Class 1E 4.16 kV Station Power Switchgear Main Circuit Breaker (1)52-40308		7	05/07/85
E-0073-0	ESD, Class 1E 4.16 kV Station Power System Switchgear, Main Circuit Breaker (1)52-40301		7	05/07/85
E-0074-0	ESD, Class 1E 4.16 kV Station Power Switchgear Main Circuit Breaker (1)52-40401		7	05/07/85
E-0075-0	ESD, Class 1E 4.16 kV Station Power Switchgear Main Circuit Breaker (1)52-40408		7	05/07/85
E-0076-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40110		6	08/06/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0077-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40210		5	08/06/85
E-0078-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40310		5	08/06/85
E-0079-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40410		5	08/06/85
E-0080-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40103		5	08/06/85
E-0081-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40203		5	08/06/85
E-0082-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40303		5	08/06/85
E-0083-0	ESD, Class 1E 4.16 kV Unit Substation Transformer Feeder Circuit Breaker (1)52-40403		5	08/06/85
E-0084-0	ESD, Class 1E 4.16 kV Station Power System Switchgear Diesel Generator Circuit Breaker (1)52-40107		8	10/03/85
E-0085-0	ESD, Class 1E 4.16 kV Station Power System Switchgear Diesel Generator Circuit Breaker (1)52-40207		8	10/03/85
E-0086-0	ESD, Class 1E 4.16 kV Station Power System Switchgear Diesel Generator Circuit Breaker (1)52-40307		8	10/03/85
E-0087-0	ESD, Class 1E 4.16 kV Station Power System Switchgear Diesel Generator Circuit Breaker (1)52-40407		8	10/03/85
E-0096-0, Sh 1	ESD, Unit Substation 480 V Feeder Circuit Breaker for Non-Class 1E Loads		5	03/19/85
E-0096-0, Sh 2	ESD, Unit Substation 480 V System Feeder Circuit Breaker for Non-Class 1E Loads		5	06/14/85
E-0097-0, Sh 1	ESD, Unit Substation 480 V System MCC & Panel Feeder Circuit Breakers		6	11/25/84
E-0097-0, Sh 2	ESD, Unit Substation 480 V System MCC & Panel Feeder Circuit Breakers		5	07/15/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0106-0, Sh A	ESD, Class 1E 4 kV Station Power System Bus A401 & A402 Diff and Overcurrent Protection (5 sheets)		11	07/03/85
E-0107-0, Sh A	ESD, DG Regular and Backup Lockout Relaying (4 sheets)		9	08/21/85
E-0108-0	ESD, Class 1E Station Power Switchgears, Circuit Breaker Failure Protection		2	08/10/84
E-0112-0, Sh 1	ESD, Station Service Transformer Protection, Group A Transformers Regular Protection		5	05/10/84
E-0112-0, Sh 2	ESD, Station Service Transformer Protection, Group A Backup Protection		7	12/21/84
E-0112-0, Sh 3	ESD, Station Service Transformer Group A Protection		4	05/01/85
E-0113-0, Sh 1	ESD, Station Service Transformer Protection, Group B Regular Protection		5	05/10/84
E-0113-0, Sh 2	ESD, Station Service Transformer Protection, Group B Backup Protection		6	08/10/84
E-0113-0, Sh 3	ESD, Station Service Transformer Group A Protection		6	08/12/85
E-0114-0, Sh 1	ESD, Station Service Transformer Protection, Group A & B Transformer Overcurrent Protection		5	07/09/84
E-0114-0, Sh 2	ESD, Station Service Transformer Protection, Group A & B Transformer Overcurrent Protection		4	05/10/84
E-0118-0, Sh 1	Schematic Meter and Relay Diagram, 250 V dc System		7	03/14/85
E-0118-0, Sh 2	Schematic Meter & Relay Diagram, 250 V dc System		4	02/17/84
E-0119-0, Sh 1	Schematic Meter & Relay Diagram, 125 V dc System		7	01/27/84
E-0119-0, Sh 2	Schematic Meter & Relay Diagram 125 V dc System		10	11/19/84
E-0119-0, Sh 3	Schematic Meter & Relay Diagram 125 V dc System		5	10/01/84
E-0146-0, Sh 1	Electrical Schematic Diagram Main Steam Pipe Drains		3	06/14/85
E-0160-0, Sh 1	ESD, Feedwater Heater 1, 2 and Drain Cooler to Vent Valves		4	05/24/85
E-0207-0, Sh A	ESD, Vacuum Breaker Solenoid Valves (4 sheets)		11	12/13/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0208-0, Sh A	ESD, 4.16 kV Circuit Breaker Control, Station Service Water Pump (5 sheets)		7	01/10/85
E-0209-0, Sh A	ESD, Station Service Water System (SSWS) (5 sheets)		5	04/23/84
E-0211-0, Sh A	ESD, SSWS Reactor Auxiliaries Cooling System Heat Exchanger Valves (7 sheets)		9	02/08/85
E-0212-0, Sh A	ESD, SSWS Strainer and Backwash Valve HV-2197 A,B,C&D (4 sheets)		9	09/18/85
E-0216-0, Sh 1	ESD, SSWS Fuel Pool & Safety Auxiliaries Cooling System (SACS) Isolation Drain Valve		3	09/24/84
E-0216-0, Sh 2	ESD, SSW Fuel Pool & SACS Makeup Isolation Valve		3	09/24/84
E-0217-0, Sh A	ESD, 4.16 kV Circuit Breaker Control Safety Auxiliary Cooling Pump (9 sheets)		5	08/21/85
E-0218-0, Sh A	ESD, SACS/Turbine Auxiliaries Cooling System (TACS) Supply & Return Valve 2522, 2496 (7 sheets)		12	08/19/85
E-0219-0, Sh 1	ESD, RHR Pump Seal & Motor Bearing Cooling Water Supply Solenoid Valves		3	03/23/84
E-0219-0, Sh 2	ESD, RHR Pump Seal & Motor Bearing Cooling Water Supply Solenoid Valves		6	03/23/84
E-0220-0, Sh A	ESD, SACS Expansion Tank & Hydraulic Accumulator Valves (4 sheets)		7	08/22/84
E-0221-0, Sh 1	ESD SACS Loop A Heat Exchanger (HX) Inlet Valves		2	04/15/85
E-0221-0, Sh 2	ESD, SACS, Loop B HX Inlet Valves		4	04/15/85
E-0223-0, Sh 1	ESD, Residual Heat Removal (RHR) HX Outlet Motor Operated Valve (MOV) 2512A		5	04/18/85
E-0223-0, Sh 2	ESD, RHR HX Outlet MOV 2512B		4	03/23/84
E-0224-0	ESD, Process Sampling Shutoff Valve		5	05/04/83
E-0225-0	ESD, SACS Fuel Pool HX Inlet Valves		6	09/25/85
E-0226-0	ESD, SACS Fuel Pool HX Cross Connection Valves		4	03/23/84
E-0227-0	ESD, Hydrogen Recombiner HX Cleaning Water Valves 2313 A/B		2	08/23/82
E-0228-0	ESD, Safety Auxiliary Cleaning SACS HX Bypass Shutoff Valves		6	12/23/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0229-0	ESD SACS Cleaning Water to Instrument Gas Compressor Valves		2	04/23/84
E-0238-0	ESD, Reactor Building Isolation Valves		2	04/30/84
E-0240-0, Sh 1	ESD, Reactor Recirculation Pump Color Isolation Valves		2	04/25/84
E-0240-0, Sh 2	ESD Reactor Recirculation Pump Isolation Valves		2	04/25/84
E-0276-0, Sh 1	ESD, Main Steam Isolation Valve (MSIV) Sealing Line Isolation Valves		4	08/13/85
E-0276-0, Sh 2	ESD, Schematic Diagram MSIV Sealing Line Isol. Val.		0	11/11/83
E-0277-0	ESD, MSIV Sealing System Instrument Gas Isolation Valves		2	04/15/85
E-0278-0	ESD MSIV Sealing System Instrument Gas Supply Valves		3	10/10/84
E-0279-0	ESD, MSIV System Test Isolation Valves		3	08/01/85
E-0297-0	ESD, Plant Leak Detection Containment Isolation Valves		3	10/23/85
E-0298-0	ESD Containment Atmosphere Control Prepurge, Cleanup Isolation Valves		2	03/14/85
E-0299-0	ESD, Containment Atmosphere Control Hydrogen/Oxygen Analyzer Isolation Valves		2	04/23/84
E-0300-0, Sh 1	ESD, Containment Atmosphere Control Bleed Valves		2	04/19/84
E-0300-0, Sh 2	ESD, Containment Atmosphere Control Bleed Valves		2	04/19/84
E-0303-0	ESD, Containment Atmosphere Control Reactor Building To Torus Vacuum Relief Valves		3	09/06/85
E-0304-0	ESD, Containment Hydrogen Recombination System Gas Recombiner Isolation Valves		3	01/10/85
E-0306-0, Sh 1	ESD, Primary Containment Instrument Gas Supply Header Isolation & Emergency Pneumatic Supply Valve		5	09/06/85
E-0306-0, Sh 2	ESD, Primary Containment Instrument Gas Supply Header Isolation & Emergency Pneumatic Supply Valve		3	08/05/85
E-0307-0	ESD, Primary Containment Instrument Gas Isolation Valves		2	05/01/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0308-0, Sh 1	ESD, Primary Containment Instrument Gas Motor-Operated Isolation Valves		4	02/13/85
E-0308-0, Sh 2	ESD, Primary Containment Instrument Gas Motor-Operated Isolation Valves		3	08/05/85
E-0310-0	ESD, Primary Containment Instrument Gas Post-Accident Compressor Suction Valves		2	02/13/85
E-0313-0	ESD, Containment Atmosphere Control Hydrogen/Oxygen Analyzer Supply Valves		4	07/22/85
E-0324-0	ESD, Fuel Pool Cooling Water Pumps		7	06/24/85
E-0326-0	ESD, Fuel Pool Filter Demineralizer System Isolation Valves		5	09/06/85
E-0329-0	ESD, Reactor Building Isolation Valves SV-4656 & 4663		4	01/09/84
E-0330-0	ESD, Torus Water Cleanup Suppression Pool Isolation Valves		3	09/06/85
E-0331-0, Sh 1	ESD, Fuel Pool Filter Demineralizer Bypass Valve		4	04/10/84
E-0331-0, Sh 2	ESD, Fuel Pool Filter Demineralizer Bypass Valve & Fuel Pool Makeup Valves		4	04/10/84
E-0436-0, Sh A	ESD, 4.16-kV Class 1E Circuit Breaker Control Chiller Compressor Index Sheet (11 sheets)		10	12/10/85
E-0350-0, Sh A	ESD, Liquid Radwaste Collection Motor Operated Valves Index Sheet (4 sheets)		5	09/06/85
E-0385-0	ESD, Solid Radwaste Collection Reactor Bldg Isolation Valve IHV-5551		4	10/11/85
E-0426-0, Sh 1	ESD, Compressed Air System Reciprocating Emergency Instrument Air Compressors		5	06/27/85
E-0426-0, Sh 2	ESD, Compressed Air System Reciprocating Emergency Instrument Air Compressors		6	09/25/85
E-0428-0	ESD, Compressed Air System Reactor Building Isolation Valves		1	01/31/83
E-0435-0, Sh A	ESD, Chilled Water Circulation Pump 1AP400 & Head Tank Makeup Water Valves (5 sheets)		7	09/11/85
E-0436-0, Sh A	ESD 4.16 kV Class 1E Circuit Breaker Control Chiller Compressor Index Sheet, (11 sheets)		10	12/20/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0465-0, Sh 1	ESD, Sch Diagram RBVS Supp Fans A/B/C VH300		6	02/25/85
E-0465-0, Sh 2	ESD, Reactor Building Ventilation System (RBVS) Supply Fans		5	08/13/85
E-0467-0, Sh A	ESD, Reactor Bldg Supply Filtration, Recirculation, & Ventilation System (9 sheets)		11	10/18/85
E-0468-0, Sh A	ESD, Reactor Bldg & SACS Pump Room Unit Coolers (5 sheets)		16	10/01/85
E-0468-0, Sh 1	ESD, NSSS Pump Room Unit Coolers (5 sheets)		8	05/24/85
E-0469-0, Sh 1	ESD, Reactor Bldg Supply Refueling Dampers Indication		5	11/26/84
E-0469-0, Sh 2	ESD, Reactor Bldg Supply Refueling Damper Indication		9	12/17/85
E-0470-0, Sh 1	ESD, Drywell Purge Damper Controls		4	09/05/86
E-0472-0, Sh A	ESD, Reactor Building Exhaust FRVS Vent Fans & Dampers (4 sheets)		10	09/02/85
E-0473-0, Sh 1	ESD, Reactor Building Exhaust Isolation Dampers		4	11/26/84
E-0473-0, Sh 2	ESD, Airlock Isolation Damper 9451F		4	10/18/84
E-0474-0, Sh A	ESD, Reactor Building Exhaust Room & Pipe Chase Isolation Dampers		7	10/24/85
E-0479-0, Sh A	ESD, Chilled Water System Containment & Reactor Building Isolation Valves (4 sheets)		2	04/30/84
E-0485-0, Sh A	ESD, Auxiliary Building Diesel Area Switchgear Room Coolers (5 sheets)		13	10/04/85
E-0486-0	ESD, Diesel Generator Room Recirculation System Fans		9	10/30/85
E-0487-0, Sh A	ESD, Auxiliary Building- Diesel Area Battery Room Exhaust Fans (6 sheets)		7	12/23/85
E-0490-0, Sh A	ESD, Auxiliary Building & Control Area, Control Room Supply Fans (5 sheets)		4	07/22/85
E-0491-0	ESD, Auxiliary Building Control Area Electro Hydraulic Air Dampers		1	11/11/82
E-0492-0, Sh A	ESD, Auxiliary Building Control Room H&V (5 sheets)		10	08/23/85
E-0492-0, Sh 3	ESD, Auxiliary Building Control Room H&V Outside Air Dampers (4 sheets)		5	08/23/85
E-0493-0, Sh A	ESD, Auxiliary Building Control Area Battery Room Exhaust Fans (4 sheets)		11	08/05/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-0495-0	ESD, Auxiliary Building Control Area Control Room Isolation Dangers		5	10/23/85
E-0496-0, Sh A	ESD, Intake Structure & Yard Building Intake Structure Supply Fans (5 sheets)		12	07/22/85
E-0497-0	ESD, Miscellaneous Structure & Yard Buildings, Intake Structure Exhaust Fans		6	11/26/84
E-1403-0, Sh A	Lighting Notes, Symbols, and Details		42	09/25/85
E-1405-1, Sh A	Class 1E Panel Schedule (34 sheets)		8	03/14/85
E-1408-0, Sh A	Wire and Cable Notes, Details (12 sheets)		19	08/26/85
E-1412-0, Sh A	Electrical Numbering System (34 sheets)		11	01/14/85
E-1417-0, Sh A	Fuse Panel Schedule (10 sheets)		3	03/14/85
E-1421-0	Single Line Lighting Distribution	9.5-20	12	05/28/85
E-1435-0	Lighting and Telephone Plan, Control & D/G Area, Plan El. 155-3 & 163-6		20	12/05/85
E-1450-1	Lighting and Telephone Plan, Turbine Building Unit 1, Plan El. 54-0		9	12/09/85
E-1451-1	Lighting and Telephone Plan, Reactor Building Unit 1, Plan El. 54-0		14	12/09/85
E-1456-1	Lighting and Telephone Plan, Turbine Building Unit 1, Plan El. 120-0		7	12/09/85
E-1456-2	Lighting and Telephone Plan, Turbine Building Unit 2, Plan El. 120-0		6	12/09/85
E-1462-1	Lighting and Telephone Plan, Turbine Building Unit 1, Plan El. 171-0		6	12/09/85
E-1467-0	Plant Area Telephone System Riser Diagram		7	12/06/85
E-1468-0, Sh 1	Riser Diagram P. A. System		14	09/05/85
E-1468-0, Sh 2	Not used			
E-1468-0, Sh 3	Not used			
E-1469-1, Sh 1	Riser Diagram-P. A. System Guardhouse		10	09/13/84
E-1469-1, Sh 2	Riser Diagram-P. A. System Guardhouse		16	10/31/85
E-1469-1, Sh 3	Riser Diagram-P. A. System Guardhouse		13	10/31/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1469-1, Sh 4	Riser Diagram-P. A. System Guardhouse		5	09/09/85
E-1469-1, Sh 5	Riser Diagram-P. A. System Guardhouse		8	09/05/85
E-1472-1	Riser Diagram Fire Detection System, Reactor and Turbine Building		9	10/31/85
E-1475-1, Sh 1	UHF Radio System Riser Diagram	9.5-33	3	08-30-85
E-1475-1, Sh 2	UHF Radio System Equipment Location	9.5-34	3	08-30-85
E-1504-0, Sh 1	Raceway Plan, Intake Structure		16	12/31/85
E-1504-0, Sh 2	Raceway Plan, Intake Structure		6	10/19/84
E-1504-0, Sh 3	Raceway Plan, Intake Structure		7	04/10/85
E-1504-0, Sh 4	Raceway Plan, Intake Structure		10	08/07/85
E-1504-0, Sh 5	Raceway Plan, Intake Structure		6	12/17/84
E-1504-0, Sh 6	Raceway Plan, Intake Structure		9	03/18/85
E-1504-0, Sh 7	Raceway Plan, Intake Structure		15	09/30/85
E-1504-0, Sh 8	Raceway Plan, Intake Structure		2	03/08/85
E-1511-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 15		5	07/17/84
E-1511-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 15		28	12/09/85
E-1512-1	Raceway Plan, Reactor Building, El 77, Area 15 (2 sheets)		20	12/21/85
E-1513-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 15		20	11/04/85
E-1513-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 15		5	10/13/83
E-1514-1, Sh 1	Raceway Plan, Reactor Building, El 132, Area 15		14	11/21/85
E-1514-1, Sh 2	Raceway Plan, Reactor Building, El 132, Area 15		4	11/19/85
E-1515-1, Sh 1	Raceway Plan, Reactor Building, El 145, Area 15		11	11/27/85
E-1515-1, Sh 2	Raceway Plan, Reactor Building, El 145, Area 15		3	08/15/85
E-1516-1	Raceway Plan, Reactor Building, El 162, Area 15		11	11/04/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1521-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 14		1	12/15/76
E-1521-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 14		19	05/28/85
E-1522-1, Sh 1	Raceway Plan, Reactor Building, El 77, Area 14		20	12/13/85
E-1522-1, Sh 2	Raceway Plan, Reactor Building, El 77, Area 14		3	12/06/83
E-1523-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 14		21	11/11/85
E-1523-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 14		9	09/23/84
E-1524-1	Raceway Plan, Reactor Building, El 124 & 132, Area 14		18	12/19/85
E-1525-1	Raceway Plan, Reactor Building, El 137 & 145, Area 14		15	11/11/85
E-1526-1, Sh 1	Raceway Plan, Reactor Building, El 162 & 178-6, Area 14		13	11/14/85
E-1526-1, Sh 2	Raceway Plan, Reactor Building, El 162 & 178-6, Area 14		11	11/11/85
E-1531-1, Sh 1	Raceway Layout, Reactor Building, El 54, Area 13		3	12/12/77
E-1531-1, Sh 2	Raceway Layout, Reactor Building, El 54, Area 13		24	12/24/85
E-1532-1, Sh 1	Raceway Plan, Reactor Building, El 77, Area 13		21	11/27/85
E-1532-1, Sh 2	Raceway Plan, Reactor Building, El 77, Area 13		5	08/11/82
E-1533-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 13		18	12/06/85
E-1533-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 13		4	04/01/83
E-1534-1	Raceway Plan, Reactor Building, El 120 & 132, Area 13		13	12/05/85
E-1535-1	Raceway Plan, Reactor Building, El 137 & 145, Area 13		15	11/21/85
E-1536-1	Raceway Plan, Reactor Building, El 162 & 178-6, Area 13		10	11/14/85
E-1537-1	Raceway Plan, Reactor Building, El 171 & 201, Area 13		8	08/16/85
E-1541-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 18		1	12/15/76
E-1541-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 18		20	11/27/85
E-1542-1	Raceway Plan, Reactor Building, El 77, Area 18		14	11/04/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1543-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 18		22	12/30/85
E-1543-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 18		4	04/24/84
E-1544-1	Raceway Plan, Reactor Building, El 132, Area 18		15	11/14/85
E-1545-1	Raceway Plan, Reactor Building, El 145, Area 18		8	11/11/85
E-1547-1	Raceway Plan, Reactor Building, El 201, Area 18		8	10/31/85
E-1551-1	Raceway Plan, Reactor Building, El 54, Area 17		1	12/15/76
E-1552-1, Sh 1	Raceway Plan, Reactor Building, El 77, Area 17		24	12/24/85
E-1552-1, Sh 2	Raceway Plan, Reactor Building, El 77, Area 17		10	09/09/85
E-1552-1, Sh 3	Raceway Plan, Reactor Building, El 77, Area 17		3	02/13/85
E-1552-1, Sh 4	Raceway Plan, Reactor Building, El 77, Area 17		4	03/28/85
E-1552-1, Sh 5	Raceway Plan, Reactor Building, El 77, Area 17		2	10/05/82
E-1552-1, Sh 6	Raceway Plan, Reactor Building, El 77, Area 17		2	10/05/82
E-1552-1, Sh 7	Raceway Plan, Reactor Building, El 77, Area 17		5	10/12/84
E-1552-1, Sh 8	Raceway Plan, Reactor Building, El 77, Area 17		4	06/19/84
E-1552-1, Sh 9	Raceway Plan, Reactor Building, El 77, Area 17		5	04/08/85
E-1552-1, Sh 10	Raceway Plan, Reactor Building, El 77, Area 17		5	03/28/85
E-1552-1, Sh 11	Raceway Plan, Reactor Building, El 77, Area 17		2	04/15/85
E-1552-1, Sh 12	Raceway Plan, Reactor Building, El 77, Area 17		1	02/07/83
E-1552-1, Sh 13	Raceway Plan, Reactor Building, El 77, Area 17		3	06/29/85
E-1552-1, Sh 14	Raceway Plan, Reactor Building, El 77, Area 17		3	04/15/85
E-1552-1, Sh 15	Raceway Plan, Reactor Building, El 77, Area 17		3	02/13/85
E-1552-1, Sh 16	Raceway Plan, Reactor Building, El 77, Area 17		2	02/22/83
E-1552-1, Sh 17	Raceway Plan, Reactor Building, El 77, Area 17		2	01/23/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1552-1, Sh 18	Raceway Plan, Reactor Building, El 77, Area 17		2	02/23/83
E-1552-1, Sh 19	Raceway Plan, Reactor Building, El 77, Area 17		4	03/26/85
E-1552-1, Sh 20	Raceway Plan, Reactor Building, El 77, Area 17		4	10/12/84
E-1552-1, Sh 21	Raceway Plan, Reactor Building, El 77, Area 17		3	12/09/83
E-1552-1, Sh 22	Raceway Plan, Reactor Building, El 77, Area 17		3	12/09/83
E-1552-1, Sh 23	Raceway Plan, Reactor Building, El 77, Area 17		1	03/30/83
E-1552-1, Sh 24	Raceway Plan, Reactor Building, El 77, Area 17		5	05/28/85
E-1552-1, Sh 25	Raceway Plan, Reactor Building, El 77, Area 17		2	02/07/83
E-1552-1, Sh 26	Raceway Plan, Reactor Building, El 77, Area 17		4	09/13/85
E-1552-1, Sh 27	Raceway Plan, Reactor Building, El 77, Area 17		1	02/07/83
E-1552-1, Sh 28	Raceway Plan, Reactor Building, El 77, Area 17		1	02/07/83
E-1552-1, Sh 29	Raceway Plan, Reactor Building, El 77, Area 17		1	06/06/83
E-1552-1, Sh 30	Raceway Plan, Reactor Building, El 77, Area 17		4	09/30/85
E-1552-1, Sh 31	Raceway Plan, Reactor Building, El 77, Area 17		3	03/27/85
E-1552-1, Sh 32	Raceway Plan, Reactor Building, El 77, Area 17		4	02/13/85
E-1552-1, Sh 33	Raceway Plan, Reactor Building, El 77, Area 17		3	08/29/85
E-1552-1, Sh 34	Raceway Plan, Reactor Building, El 77, Area 17		3	07/20/84
E-1552-1, Sh 35	Raceway Plan, Reactor Building, El 77, Area 17		2	08/29/84
E-1552-1, Sh 36	Raceway Plan, Reactor Building, El 77, Area 17		0	10/05/84
E-1552-1, Sh 37	Raceway Plan, Reactor Building, El 77, Area 17		0	11/21/84
E-1552-1, Sh 38	Raceway Plan, Reactor Building, El 77, Area 17		0	12/07/84
E-1552-1, Sh 39	Raceway Plan, Reactor Building, El 77, Area 17		0	12/07/84
E-1552-1, Sh 40	Raceway Plan, Reactor Building, El 77, Area 17		0	12/07/84

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1552-1, Sh 41	Raceway Plan, Reactor Building, El 77, Area 17		0	12/07/84
E-1553-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 17		18	12/09/85
E-1553-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 17		12	03/12/85
E-1553-1, Sh 3	Raceway Plan, Reactor Building, El 102, Area 17		12	08/19/85
E-1553-1, Sh 4	Raceway Plan, Reactor Building, El 102, Area 17		7	08/12/85
E-1553-1, Sh 5	Raceway Plan, Reactor Building, El 102, Area 17		7	12/07/84
E-1553-1, Sh 6	Raceway Plan, Reactor Building, El 102, Area 17		3	10/26/84
E-1553-1, Sh 7	Raceway Plan, Reactor Building, El 102, Area 17		3	12/19/84
E-1553-1, Sh 8	Raceway Plan, Reactor Building, El 102, Area 17		5	08/29/85
E-1553-1, Sh 9	Raceway Plan, Reactor Building, El 102, Area 17		8	12/03/84
E-1553-1, Sh 10	Raceway Plan, Reactor Building, El 102, Area 17		6	12/03/84
E-1553-1, Sh 11	Raceway Plan, Reactor Building, El 102, Area 17		4	08/26/83
E-1553-1, Sh 12	Raceway Plan, Reactor Building, El 102, Area 17		3	05/28/85
E-1553-1, Sh 13	Raceway Plan, Reactor Building, El 102, Area 17		3	08/12/85
E-1553-1, Sh 14	Raceway Plan, Reactor Building, El 102, Area 17		5	08/12/85
E-1553-1, Sh 15	Raceway Plan, Reactor Building, El 102, Area 17		4	04/17/85
E-1553-1, Sh 16	Raceway Plan, Reactor Building, El 102, Area 17		5	11/28/84
E-1553-1, Sh 17	Raceway Plan, Reactor Building, El 102, Area 17		2	12/02/82
E-1553-1, Sh 18	Raceway Plan, Reactor Building, El 102, Area 17		4	08/16/85
E-1553-1, Sh 19	Raceway Plan, Reactor Building, El 102, Area 17		2	10/05/82
E-1553-1, Sh 20	Raceway Plan, Reactor Building, El 102, Area 17		3	02/23/84
E-1553-1, Sh 21	Raceway Plan, Reactor Building, El 102, Area 17		6	04/25/85
E-1553-1, Sh 22	Raceway Plan, Reactor Building, El 102, Area 17		7	08/16/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1553-1, Sh 23	Raceway Plan, Reactor Building, El 102, Area 17		6	03/26/85
E-1553-1, Sh 24	Raceway Plan, Reactor Building, El 102, Area 17		6	03/26/85
E-1553-1, Sh 25	Raceway Plan, Reactor Building, El 102, Area 17		6	03/21/85
E-1553-1, Sh 26	Raceway Plan, Reactor Building, El 102, Area 17		6	04/17/85
E-1553-1, Sh 27	Raceway Plan, Reactor Building, El 102, Area 17		9	04/25/85
E-1553-1, Sh 28	Raceway Plan, Reactor Building, El 102, Area 17		3	02/23/84
E-1553-1, Sh 29	Raceway Plan, Reactor Building, El 102, Area 17		4	01/14/85
E-1553-1, Sh 30	Raceway Plan, Reactor Building, El 102, Area 17		2	04/13/83
E-1553-1, Sh 31	Raceway Plan, Reactor Building, El 102, Area 17		4	01/23/85
E-1553-1, Sh 32	Raceway Plan, Reactor Building, El 102, Area 17		2	12/19/84
E-1553-1, Sh 33	Raceway Plan, Reactor Building, El 102, Area 17		4	06/29/85
E-1553-1, Sh 34	Raceway Plan, Reactor Building, El 102, Area 17		4	10/18/84
E-1553-1, Sh 35	Raceway Plan, Reactor Building, El 102, Area 17		3	04/13/84
E-1553-1, Sh 36	Raceway Plan, Reactor Building, El 102, Area 17		6	09/13/85
E-1553-1, Sh 37	Raceway Plan, Reactor Building, El 102, Area 17		4	11/16/84
E-1553-1, Sh 38	Raceway Plan, Reactor Building, El 102, Area 17		5	10/18/84
E-1553-1, Sh 39	Raceway Plan, Reactor Building, El 102, Area 17		7	09/30/85
E-1553-1, Sh 40	Raceway Plan, Reactor Building, El 102, Area 17		3	08/26/83
E-1553-1, Sh 41	Raceway Plan, Reactor Building, El 102, Area 17		1	10/01/82
E-1553-1, Sh 42	Raceway Plan, Reactor Building, El 102, Area 17		1	10/01/82
E-1553-1, Sh 43	Raceway Plan, Reactor Building, El 102, Area 17		17	11/19/85
E-1553-1, Sh 44	Raceway Plan, Reactor Building, El 102, Area 17		2	09/07/84
E-1553-1, Sh 45	Raceway Plan, Reactor Building, El 102, Area 17		7	09/13/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1553-1, Sh 46	Raceway Plan, Reactor Building, El 102, Area 17		3	12/05/84
E-1553-1, Sh 47	Raceway Plan, Reactor Building, El 102, Area 17		4	12/03/84
E-1553-1, Sh 48	Raceway Plan, Reactor Building, El 102, Area 17		5	03/11/85
E-1553-1, Sh 49	Raceway Plan, Reactor Building, El 102, Area 17		4	06/07/84
E-1553-1, Sh 50	Raceway Plan, Reactor Building, El 102, Area 17		4	05/16/85
E-1553-1, Sh 51	Raceway Plan, Reactor Building, El 102, Area 17		4	08/24/84
E-1553-1, Sh 52	Raceway Plan, Reactor Building, El 102, Area 17		5	10/08/84
E-1553-1, Sh 53	Raceway Plan, Reactor Building, El 102, Area 17		1	04/24/84
E-1553-1, Sh 54	Raceway Plan, Reactor Building, El 102, Area 17		4	09/30/85
E-1553-1, Sh 55	Raceway Plan, Reactor Building, El 102, Area 17		1	05/09/85
E-1553-1, Sh 56	Raceway Plan, Reactor Building, El 102, Area 17		1	02/22/83
E-1553-1, Sh 57	Raceway Plan, Reactor Building, El 102, Area 17		3	10/05/84
E-1553-1, Sh 58	Raceway Plan, Reactor Building, El 102, Area 17		2	01/23/85
E-1553-1, Sh 59	Raceway Plan, Reactor Building, El 102, Area 17		1	02/07/83
E-1553-1, Sh 60	Raceway Plan, Reactor Building, El 102, Area 17		5	05/28/85
E-1553-1, Sh 61	Raceway Plan, Reactor Building, El 102, Area 17		4	06/07/84
E-1553-1, Sh 62	Raceway Plan, Reactor Building, El 102, Area 17		1	02/07/83
E-1553-1, Sh 63	Raceway Plan, Reactor Building, El 102, Area 17		5	04/15/85
E-1553-1, Sh 64	Raceway Plan, Reactor Building, El 102, Area 17		2	02/24/83
E-1553-1, Sh 65	Raceway Plan, Reactor Building, El 102, Area 17		2	01/23/85
E-1553-1, Sh 66	Raceway Plan, Reactor Building, El 102, Area 17		2	02/13/85
E-1553-1, Sh 67	Raceway Plan, Reactor Building, El 102, Area 17		1	02/07/83
E-1553-1, Sh 68	Raceway Plan, Reactor Building, El 102, Area 17		4	08/12/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1553-1, Sh 69	Raceway Plan, Reactor Building, El 102, Area 17		0	11/12/82
E-1553-1, Sh 70	Raceway Plan, Reactor Building, El 102, Area 17		4	08/29/85
E-1553-1, Sh 71	Raceway Plan, Reactor Building, El 102, Area 17		5	08/29/85
E-1553-1, Sh 72	Raceway Plan, Reactor Building, El 102, Area 17		5	04/01/85
E-1553-1, Sh 73	Raceway Plan, Reactor Building, El 102, Area 17		2	04/03/84
E-1553-1, Sh 74	Raceway Plan, Reactor Building, El 102, Area 17		4	09/09/85
E-1553-1, Sh 75	Raceway Plan, Reactor Building, El 102, Area 17		6	03/20/85
E-1553-1, Sh 76	Raceway Plan, Reactor Building, El 102, Area 17		3	02/22/85
E-1553-1, Sh 77	Raceway Plan, Reactor Building, El 102, Area 17		2	03/21/84
E-1553-1, Sh 78	Raceway Plan, Reactor Building, El 102, Area 17		2	12/19/84
E-1553-1, Sh 79	Raceway Plan, Reactor Building, El 102, Area 17		1	09/13/85
E-1553-1, Sh 80	Raceway Plan, Reactor Building, El 102, Area 17		4	09/13/85
E-1553-1, Sh 81	Raceway Plan, Reactor Building, El 102, Area 17		2	12/07/84
E-1553-1, Sh 82	Raceway Plan, Reactor Building, El 102, Area 17		3	08/29/84
E-1553-1, Sh 83	Raceway Plan, Reactor Building, El 102, Area 17		5	12/19/84
E-1553-1, Sh 84	Raceway Plan, Reactor Building, El 102, Area 17		2	03/26/84
E-1553-1, Sh 85	Raceway Plan, Reactor Building, El 102, Area 17		3	09/09/85
E-1553-1, Sh 86	Raceway Plan, Reactor Building, El 102, Area 17		7	09/13/85
E-1553-1, Sh 87	Raceway Plan, Reactor Building, El 102, Area 17		3	07/18/85
E-1553-1, Sh 88	Raceway Plan, Reactor Building, El 102, Area 17		3	04/27/84
E-1553-1, Sh 89	Raceway Plan, Reactor Building, El 102, Area 17		6	08/12/85
E-1553-1, Sh 90	Raceway Plan, Reactor Building, El 102, Area 17		5	07/18/85
E-1553-1, Sh 91	Raceway Plan, Reactor Building, El 102, Area 17		2	07/22/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1553-1, Sh 92	Raceway Plan, Reactor Building, El 102, Area 17		2	09/13/85
E-1553-1, Sh 93	Raceway Plan, Reactor Building, El 102, Area 17		1	04/08/85
E-1553-1, Sh 94	Raceway Plan, Reactor Building, El 102, Area 17		1	04/08/85
E-1553-1, Sh 95	Raceway Plan, Reactor Building, El 102, Area 17		1	11/26/84
E-1553-1, Sh 96	Raceway Plan, Reactor Building, El 102, Area 17		2	04/08/85
E-1553-1, Sh 97	Raceway Plan, Reactor Building, El 102, Area 17		2	07/18/85
E-1553-1, Sh 98	Raceway Plan, Reactor Building, El 102, Area 17		3	08/19/85
E-1553-1, Sh 99	Raceway Plan, Reactor Building, El 102, Area 17		0	03/14/85
E-1554-1, Sh 1	Raceway Plan, Reactor Building, El 132, Area 17		14	11/22/85
E-1554-1, Sh 2	Raceway Plan, Reactor Building, El 132, Area 17		12	08/19/85
E-1554-1, Sh 3	Raceway Plan, Reactor Building, El 132, Area 17		2	12/02/82
E-1554-1, Sh 4	Raceway Plan, Reactor Building, El 132, Area 17		5	05/07/85
E-1554-1, Sh 5	Raceway Plan, Reactor Building, El 132, Area 17		3	08/16/84
E-1554-1, Sh 6	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/82
E-1554-1, Sh 7	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/82
E-1554-1, Sh 8	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/82
E-1554-1, Sh 9	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/82
E-1554-1, Sh 10	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/83
E-1554-1, Sh 11	Raceway Plan, Reactor Building, El 132, Area 17		3	02/23/84
E-1554-1, Sh 12	Raceway Plan, Reactor Building, El 132, Area 17		3	12/09/83
E-1554-1, Sh 13	Raceway Plan, Reactor Building, El 132, Area 17		5	08/21/84
E-1554-1, Sh 14	Raceway Plan, Reactor Building, El 132, Area 17		5	05/09/85
E-1554-1, Sh 15	Raceway Plan, Reactor Building, El 132, Area 17		3	10/01/84

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1554-1, Sh 16	Raceway Plan, Reactor Building, El 132, Area 17		2	04/25/85
E-1554-1, Sh 17	Raceway Plan, Reactor Building, El 132, Area 17		2	05/16/85
E-1554-1, Sh 18	Raceway Plan, Reactor Building, El 132, Area 17		3	08/29/85
E-1554-1, Sh 19	Raceway Plan, Reactor Building, El 132, Area 17		2	12/19/84
E-1554-1, Sh 20	Raceway Plan, Reactor Building, El 132, Area 17		7	08/29/85
E-1554-1, Sh 21	Raceway Plan, Reactor Building, El 132, Area 17		5	08/29/85
E-1554-1, Sh 22	Raceway Plan, Reactor Building, El 132, Area 17		6	08/29/85
E-1554-1, Sh 23	Raceway Plan, Reactor Building, El 132, Area 17		6	06/29/85
E-1554-1, Sh 24	Raceway Plan, Reactor Building, El 132, Area 17		4	08/29/85
E-1554-1, Sh 25	Raceway Plan, Reactor Building, El 132, Area 17		5	01/23/85
E-1554-1, Sh 26	Raceway Plan, Reactor Building, El 132, Area 17		4	05/15/84
E-1554-1, Sh 27	Raceway Plan, Reactor Building, El 132, Area 17		4	08/29/85
E-1554-1, Sh 28	Raceway Plan, Reactor Building, El 132, Area 17		4	08/29/85
E-1554-1, Sh 29	Raceway Plan, Reactor Building, El 132, Area 17		3	05/09/85
E-1554-1, Sh 30	Raceway Plan, Reactor Building, El 132, Area 17		4	08/29/85
E-1554-1, Sh 31	Raceway Plan, Reactor Building, El 132, Area 17		4	02/13/85
E-1554-1, Sh 32	Raceway Plan, Reactor Building, El 132, Area 17		5	08/29/85
E-1554-1, Sh 33	Raceway Plan, Reactor Building, El 132, Area 17		5	08/12/85
E-1554-1, Sh 34	Raceway Plan, Reactor Building, El 132, Area 17		2	08/24/84
E-1554-1, Sh 35	Raceway Plan, Reactor Building, El 132, Area 17		6	08/29/85
E-1554-1, Sh 36	Raceway Plan, Reactor Building, El 132, Area 17		4	08/16/84
E-1554-1, Sh 37	Raceway Plan, Reactor Building, El 132, Area 17		4	09/30/85
E-1554-1, Sh 38	Raceway Plan, Reactor Building, El 132, Area 17		2	04/15/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1554-1, Sh 39	Raceway Plan, Reactor Building, El 132, Area 17		5	11/26/84
E-1554-1, Sh 40	Raceway Plan, Reactor Building, El 132, Area 17		7	02/19/85
E-1554-1, Sh 41	Raceway Plan, Reactor Building, El 132, Area 17		2	06/07/84
E-1554-1, Sh 42	Raceway Plan, Reactor Building, El 132, Area 17		3	08/29/85
E-1554-1, Sh 43	Raceway Plan, Reactor Building, El 132, Area 17		3	08/29/85
E-1554-1, Sh 44	Raceway Plan, Reactor Building, El 132, Area 17		3	06/04/84
E-1554-1, Sh 45	Raceway Plan, Reactor Building, El 132, Area 17		7	08/29/85
E-1554-1, Sh 46	Raceway Plan, Reactor Building, El 132, Area 17		3	01/23/85
E-1554-1, Sh 47	Raceway Plan, Reactor Building, El 132, Area 17		2	12/03/84
E-1554-1, Sh 48	Raceway Plan, Reactor Building, El 132, Area 17		3	06/19/84
E-1554-1, Sh 49	Raceway Plan, Reactor Building, El 132, Area 17		1	04/27/84
E-1554-1, Sh 50	Raceway Plan, Reactor Building, El 132, Area 17		3	08/29/85
E-1554-1, Sh 51	Raceway Plan, Reactor Building, El 132, Area 17		2	08/01/84
E-1554-1, Sh 52	Raceway Plan, Reactor Building, El 132, Area 17		4	03/11/85
E-1554-1, Sh 53	Raceway Plan, Reactor Building, El 132, Area 17		3	06/19/84
E-1554-1, Sh 54	Raceway Plan, Reactor Building, El 132, Area 17		3	12/20/84
E-1554-1, Sh 55	Raceway Plan, Reactor Building, El 132, Area 17		1	05/23/84
E-1554-1, Sh 56	Raceway Plan, Reactor Building, El 132, Area 17		5	07/05/85
E-1554-1, Sh 57	Raceway Plan, Reactor Building, El 132, Area 17		2	06/19/84
E-1554-1, Sh 58	Raceway Plan, Reactor Building, El 132, Area 17		5	08/19/85
E-1554-1, Sh 59	Raceway Plan, Reactor Building, El 132, Area 17		4	08/29/85
E-1554-1, Sh 60	Raceway Plan, Reactor Building, El 132, Area 17		2	09/09/85
E-1554-1, Sh 61	Raceway Plan, Reactor Building, El 132, Area 17		3	09/09/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1554-1, Sh 62	Raceway Plan, Reactor Building, El 132, Area 17		4	09/09/85
E-1554-1, Sh 63	Raceway Plan, Reactor Building, El 132, Area 17		2	12/03/84
E-1554-1, Sh 64	Raceway Plan, Reactor Building, El 132, Area 17		4	09/09/85
E-1554-1, Sh 65	Raceway Plan, Reactor Building, El 132, Area 17		2	03/28/85
E-1554-1, Sh 66	Raceway Plan, Reactor Building, El 132, Area 17		2	12/19/84
E-1554-1, Sh 67	Raceway Plan, Reactor Building, El 132, Area 17		1	05/16/85
E-1554-1, Sh 68	Raceway Plan, Reactor Building, El 132, Area 17		2	05/09/85
E-1554-1, Sh 69	Raceway Plan, Reactor Building, El 132, Area 17		0	08/21/84
E-1554-1, Sh 70	Raceway Plan, Reactor Building, El 132, Area 17		2	06/12/85
E-1554-1, Sh 71	Raceway Plan, Reactor Building, El 132, Area 17		1	09/21/84
E-1554-1, Sh 72	Raceway Plan, Reactor Building, El 132, Area 17		0	12/19/84
E-1555-1, Sh 1	Raceway Plan, Reactor Building, El 145, Area 17		15	11/14/85
E-1555-1, Sh 2	Raceway Plan, Reactor Building, El 145, Area 17		6	04/04/85
E-1555-1, Sh 3	Raceway Plan, Reactor Building, El 145, Area 17		2	05/26/83
E-1555-1, Sh 4	Raceway Plan, Reactor Building, El 145, Area 17		3	04/17/84
E-1555-1, Sh 5	Raceway Plan, Reactor Building, El 145, Area 17		4	04/17/84
E-1555-1, Sh 6	Raceway Plan, Reactor Building, El 145, Area 17		3	12/09/83
E-1555-1, Sh 7	Raceway Plan, Reactor Building, El 145, Area 17		6	04/17/85
E-1555-1, Sh 8	Raceway Plan, Reactor Building, El 145, Area 17		8	04/17/85
E-1555-1, Sh 9	Raceway Plan, Reactor Building, El 145, Area 17		2	06/11/84
E-1555-1, Sh 10	Raceway Plan, Reactor Building, El 145, Area 17		4	04/15/85
E-1555-1, Sh 11	Raceway Plan, Reactor Building, El 145, Area 17		3	06/19/84
E-1555-1, Sh 12	Raceway Plan, Reactor Building, El 145, Area 17		4	04/15/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1555-1, Sh 13	Raceway Plan, Reactor Building, El 145, Area 17		1	06/07/84
E-1555-1, Sh 14	Raceway Plan, Reactor Building, El 145, Area 17		4	04/17/85
E-1556-1, Sh 1	Raceway Plan, Reactor Building, El 162, Area 17		16	11/15/85
E-1556-1, Sh 2	Raceway Plan, Reactor Building, El 162, Area 17		3	03/19/84
E-1556-1, Sh 3	Raceway Plan, Reactor Building, El 162, Area 17		13	06/28/85
E-1556-1, Sh 4	Raceway Plan, Reactor Building, El 162, Area 17		3	07/30/84
E-1556-1, Sh 5	Raceway Plan, Reactor Building, El 162, Area 17		4	04/05/85
E-1556-1, Sh 6	Raceway Plan, Reactor Building, El 162, Area 17		11	09/30/85
E-1556-1, Sh 7	Raceway Plan, Reactor Building, El 162, Area 17		11	04/16/85
E-1556-1, Sh 8	Raceway Plan, Reactor Building, El 162, Area 17		5	07/18/85
E-1556-1, Sh 9	Raceway Plan, Reactor Building, El 162, Area 17		10	10/24/85
E-1556-1, Sh 10	Raceway Plan, Reactor Building, El 162, Area 17		8	11/19/85
E-1556-1, Sh 11	Raceway Plan, Reactor Building, El 162, Area 17		5	10/02/85
E-1556-1, Sh 12	Raceway Plan, Reactor Building, El 162, Area 17		3	03/12/85
E-1556-1, Sh 13	Raceway Plan, Reactor Building, El 162, Area 17		3	03/20/85
E-1556-1, Sh 14	Raceway Plan, Reactor Building, El 162, Area 17		2	01/31/85
E-1556-1, Sh 15	Raceway Plan, Reactor Building, El 162, Area 17		5	04/16/85
E-1556-1, Sh 16	Raceway Plan, Reactor Building, El 162, Area 17		4	04/25/85
E-1556-1, Sh 17	Raceway Plan, Reactor Building, El 162, Area 17		8	08/19/85
E-1556-1, Sh 18	Raceway Plan, Reactor Building, El 162, Area 17		5	07/23/85
E-1556-1, Sh 19	Raceway Plan, Reactor Building, El 162, Area 17		3	04/01/85
E-1556-1, Sh 20	Raceway Plan, Reactor Building, El 162, Area 17		3	04/04/85
E-1556-1, Sh 21	Raceway Plan, Reactor Building, El 162, Area 17		4	06/07/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1556-1, Sh 24	Raceway Sections & Details, Reactor Building Area		6	11/19/85
E-1561-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 16		1	12/15/76
E-1561-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 16		15	12/09/85
E-1562-1	Raceway Plan, Reactor Building, El 77, Area 16		18	12/06/85
E-1563-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 16		20	12/06/85
E-1563-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 16		4	03/12/85
E-1564-1	Raceway Plan, Reactor Building, El 132, Area 16		14	11/27/85
E-1565-1	Raceway Plan, Reactor Building, El 145, Area 16		16	11/04/85
E-1566-1, Sh 1	Raceway Plan, Reactor Building, El 162, Area 16		14	12/19/85
E-1566-1, Sh 2	Raceway Plan, Reactor Building, El 162, Area 16		9	12/19/85
E-1566-1, Sh 3	Raceway Plan, Reactor Building, El 162, Area 16		3	04/04/85
E-1567-1	Raceway Plan, Reactor Building, El 201, Area 16		9	12/19/85
E-1571-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 21		4	02/07/84
E-1571-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 21		26	12/07/85
E-1572-1	Raceway Plan, Reactor Building, El 77, Area 21		20	12/06/85
E-1573-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 21		19	12/24/85
E-1573-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 21		6	07/07/83
E-1574-1	Raceway Plan, Reactor Building, El 132, Area 21		10	12/19/85
E-1575-1	Raceway Plan, Reactor Building, El 145, Area 21		8	11/27/85
E-1576-1	Raceway Plan, Reactor Building, El 162, Area 21		11	12/19/85
E-1577-1	Raceway Plan, Reactor Building, El 201, Area 21		8	12/12/85
E-1581-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 20		2	06/07/82
E-1581-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 20		17	10/31/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1582-1	Raceway Plan, Reactor Building, El 77, Area 20		12	12/06/85
E-1583-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 20		17	12/24/85
E-1583-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 20		4	01/31/85
E-1584-1	Raceway Plan, Reactor Building, El 132, Area 20		13	11/27/85
E-1585-1	Raceway Plan, Reactor Building, El 145, Area 20		12	11/27/85
E-1586-1	Raceway Plan, Reactor Building, El 162, Area 20		12	08/29/85
E-1587-1	Raceway Plan, Reactor Building, El 201, Area 20		7	11/21/85
E-1591-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 19		1	12/15/76
E-1591-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 19		26	10/31/85
E-1592-1	Raceway Plan, Reactor Building, El 77, Area 19		21	12/06/85
E-1593-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 19		19	12/24/85
E-1593-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 19		3	12/10/82
E-1594-1	Raceway Plan, Reactor Building, El 132, Area 19		10	11/27/85
E-1595-1	Raceway Plan, Reactor Building, El 145, Area 19		14	12/19/85
E-1596-1	Raceway Plan, Reactor Building, El 162, Area 19		17	12/19/85
E-1597-1	Raceway Plan, Reactor Building, El 201, Area 19		6	12/19/85
E-1611-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 24		4	06/07/82
E-1611-1, Sh 2	Raceway Layout, Reactor Building, El 54, Area 24		24	12/24/85
E-1612-1	Raceway Plan, Reactor Building, El 77, Area 24		17	11/04/85
E-1613-1, Sh 1	Raceway Plan, Reactor Building, El 102, Area 24		14	12/24/85
E-1613-1, Sh 2	Raceway Plan, Reactor Building, El 102, Area 24		4	03/24/83
E-1621-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 23		4	06/07/82
E-1621-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 23		28	01/02/86

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1622-1	Raceway Plan, Reactor Building, El 77, Area 23		13	11/04/85
E-1623-1	Raceway Plan, Reactor Building, El 102, Area 23		13	03/14/85
E-1631-1, Sh 1	Raceway Plan, Reactor Building, El 54, Area 22		4	02/16/84
E-1631-1, Sh 2	Raceway Plan, Reactor Building, El 54, Area 22		24	01/02/86
E-1632-1	Raceway Plan, Reactor Building, El 77, Area 22		22	12/30/85
E-1633-1	Raceway Plan, Reactor Building, El 102, Area 22		18	12/24/85
E-1651-1, Sh 1	Raceway Plan, Auxiliary Building Control Area, El 54, Area 25		6	03/18/85
E-1651-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 54, Area 25		32	11/20/85
E-1651-1, Sh 3	Raceway Plan, Auxiliary Building, Control Area, El 54, Area 25		4	08/19/85
E-1651-1, Sh 4	Raceway Plan, Auxiliary Building, Control Area, El 54, Area 25		2	08/19/85
E-1652-1, Sh 1	Raceway Plan, Auxiliary Building, Control Area, El 77, Area 25		28	12/12/85
E-1652-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 77, Area 25		18	12/12/85
E-1653-1	Raceway Plan, Auxiliary Building, Control Area, El 102, Area 25		29	01/02/86
E-1654-1, Sh 1	Raceway Plan, Auxiliary Building, Control Area, El 117-6, Area 25		12	11/13/85
E-1654-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 124, Area 25		15	01/02/86
E-1654-1, Sh 3	Raceway Plan, Auxiliary Building, El 124, Area 25		10	12/23/85
E-1654-1, Sh 4	Raceway Plan, Auxiliary Building Control Area 26 Plan at El 124-0		20	11/20/85
E-1655-1	Raceway Plan, Auxiliary Building, Control Area, El 137, Area 25		24	11/21/85
E-1656-1, Sh 1	Raceway Plan, Auxiliary Building, Control Area, El 155-3, Area 25		4	10/01/84
E-1656-1, Sh 2	Raceway Plan, Auxiliary Building, Control Plan at El 155-3, Area 25		17	12/23/85
E-1661-1, Sh 1	Raceway Plan, Auxiliary Building Control Area, El 54, Area 26		3	06/07/78
E-1661-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 54, Area 26		26	09/13/85
E-1662-1, Sh 1	Raceway Layout, Auxiliary Building, Control Area, El 77, Area 26		32	11/27/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1662-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 77, Area 26		18	11/27/85
E-1663-1	Raceway Plan, Auxiliary Building, Control Area, El 102, Area 26		28	12/31/85
E-1664-1, Sh 1	Raceway Plan, Auxiliary Building, Control Area, El 117-6, Area 26		13	12/23/85
E-1664-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 124, Area 26		19	01/02/86
E-1664-1, Sh 3	Raceway Plan, Auxiliary Building, Control Area, El 124, Area 26		12	11/21/85
E-1664-1, Sh 4	Raceway Plan, Auxiliary Building, Control Area, El 124, Area 26		17	11/21/85
E-1664-1, Sh 6	Raceway Plan, Auxiliary Building, Control Area, El 124, Area 26		18	11/04/85
E-1665-1	Raceway Plan, Auxiliary Building, Control Area, El 137, Area 26		23	11/21/85
E-1666-1, Sh 1	Raceway Plan, Auxiliary Building, Control Area, El 155-3, Area 26		2	07/08/81
E-1666-1, Sh 2	Raceway Plan, Auxiliary Building, Control Area, El 155-3, Area 26		14	11/13/85
E-1671-1, Sh 1	Raceway Plan, Auxiliary Building, Diesel Area, El 54, Area 27		3	05/20/82
E-1671-1, Sh 2	Raceway Plan, Auxiliary Building, Diesel Area, El 54, Area 27		22	12/07/84
E-1672-1	Raceway Plan, Auxiliary Building, Diesel Area, El 77, Area 27		18	11/27/85
E-1673-1	Raceway Plan, Auxiliary Building, Diesel Area, El 102, Area 27 (2 sheets)		24	12/12/85
E-1675-1	Raceway Plan, Auxiliary Building, Diesel Area, El 130, Area 27		22	11/13/85
E-1676-1	Raceway Plan, Auxiliary Building, Diesel Area, El 150, Area 27		20	11/27/85
E-1677-1	Raceway Plan, Auxiliary Building, Diesel Area, El 163-6, Area 27		18	11/21/85
E-1680-1, Sh 1	Raceway Plan Auxiliary Building, Diesel Generator Area, El 178-0, Area 27		2	05/11/84
E-1680-1, Sh 2	Raceway Plan Auxiliary Building, Diesel Generator Area, El 178-0, Area 27		14	11/21/8 5
E-1681-1, Sh 1	Raceway Plan, Auxiliary Building, Diesel Generator Area, El 54, Area 28		2	05/21/82
E-1681-1, Sh 2	Raceway Plan, Auxiliary Building, Diesel Generator Area, El 54, Area 28		22	11/21/85
E-1682-1	Raceway Plan, Auxiliary Building, Diesel Generator Area, El 77, Area 28		21	11/21/85
E-1683-1	Raceway Plan, Auxiliary Building, Diesel Area, El 102, Area 28		25	11/27/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1685-1	Raceway Plan, Auxiliary Building, Diesel Area, El 130, Area 28		22	12/23/85
E-1686-1	Raceway Plan, Auxiliary Building, Diesel Area, El 150, Area 28		21	12/23/85
E-1687-1, Sh 1	Raceway Plan, Auxiliary Building, Diesel Area, El 160, Area 28		15	11/21/85
E-1687-1, Sh 2	Raceway Plan, Auxiliary Building, Diesel Area, El 160, Area 28		1	08/09/82
E-1687-2	Raceway Plan, Auxiliary Building, Control Area, El 163-6, Area 68		13	11/21/85
E-1690-1, Sh 1	Raceway Plan, Auxiliary Building Diesel Generator Area, El 178, Area 28		13	11/21/85
E-1690-1, Sh 2	Raceway Plan, Auxiliary Building Diesel Generator Area, El 178-0, Area 28		-	---
E-1695-0	Embedded Conduits, Auxiliary Building, El 102, Areas 27, 28, 67 & 68		14	09/09/85
E-1700-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 38		14	11/27/85
E-1701-0, Sh 1	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 78		2	01/18/83
E-1701-0, Sh 2	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 78		13	11/27/85
E-1712-0, Sh 1	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 73		3	06/14/83
E-1712-0, Sh 2	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 73		17	11/15/85
E-1714-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 72		18	12/12/85
E-1716-0, Sh 1	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 71		1	11/19/76
E-1716-0, Sh 2	Raceway Plan, Auxiliary Building, Radwaste Area, El 54, Area 71		10	01/18/85
E-1721-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 78		17	10/10/85
E-1723-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 77		10	10/10/85
E-1725-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 76		13	10/10/85
E-1726-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 35		21	10/28/85
E-1729-0	Auxiliary Building & Radwaste Area, Raceway Partial Plans, El 75		8	11/04/85
E-1730-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 34		26	12/31/85
E-1732-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 73		26	11/27/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1734-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 72		17	08/07/85
E-1736-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 87, Area 71		19	11/04/85
E-1741-0	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 78		17	09/24/85
E-1743-0, Sh 1	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 77		16	10/10/85
E-1743-0, Sh 2	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 77		-	---
E-1750-0, Sh 1	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 34		25	12/12/85
E-1750-0, Sh 2	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 34		10	10/24/85
E-1750-0, Sh 3	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 34		5	05/23/84
E-1750-0, Sh 4	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 34		4	06/07/84
E-1750-0, Sh 5	Raceway Plan, Auxiliary Building, Service Area, El 102, Area 34		9	05/31/84
E-1752-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 102, Area 73		25	12/31/85
E-1754-0, Sh 1	Raceway Plan, Auxiliary Building, Radwaste Area, El 102, Area 72		22	12/31/85
E-1754-0, Sh 2	Raceway Plan, Auxiliary Building Service Area, El 102, Area 72		10	11/11/84
E-1756-0	Raceway Plan, Auxiliary Building, Radwaste Area, El 102, Area 71		21	11/21/85
E-1761-0	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 77		6	01/25/85
E-1763-0	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 76		6	12/20/84
E-1764-0, Sh 1	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 35		14	08/20/84
E-1764-0, Sh 2	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 35		4	10/13/83
E-1764-0, Sh 3	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 35		4	06/16/83
E-1767-0	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 73		20	10/10/85
E-1769-0	Raceway Plan, Auxiliary Building, Service Area, El 124, Area 72		8	12/31/85
E-1773-0	Raceway Plan, Auxiliary Building, Service Area, El 137, Area 76		7	01/23/84
E-1777-0	Raceway Plan, Auxiliary Building, Service Area, El 137, Area 73		19	12/31/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-1801-1, Sh 2	Raceway Plan, Turbine Building, El 54, Area 04		18	12/09/85
E-1804-0, Sh 1	Raceway Plan, Turbine Building, El 102, Area 41		20	02/13/85
E-1804-0, Sh 2	Raceway Plan, Turbine Building, El 102, Area 41		5	06/20/84
E-1815-1	Raceway Plan, Turbine Building, El 137, Area 03		13	12/22/85
E-1825-1	Raceway Plan, Turbine Building, El 137, Area 02		10	11/22/85
E-1833-1, Sh 1	Raceway Plan, Turbine Building, El 102 & 120, Area 01		20	11/22/85
E-1833-1, Sh 2	Raceway Sections & Details, Turbine Building, El 102 & 120, Area 01		4	11/22/85
E-1853-1, Sh 1	Raceway Plan, Turbine Building, El 102, Area 08		20	11/13/85
E-1853-1, Sh 2	Raceway Plan, Turbine Building, El 102, Area 08		6	08/26/83
E-1854-1	Raceway Plan, Turbine Building, El 120, Area 08		17	03/28/85
E-1863-1, Sh 1	Raceway Plan, Turbine Building, El 102 & 120, Area 07		14	12/24/85
E-1863-1, Sh 2	Raceway Plan, Turbine Building, El 102 & 120, Area 07		1	09/28/83
E-1865-1	Raceway Plan, Turbine Building, El 137 & 145, Area 07		13	12/07/84
E-1875-1	Raceway Plan, Turbine Building, El 137, Area 06		13	11/22/85
E-1903-1, Sh 1	Raceway Plan, Turbine Building, El 102, Area 12		19	11/13/85
E-1903-1, Sh 2	Raceway Plan, Turbine Building, El 102, Area 12		4	05/21/84
E-1925-1	Raceway Plan, Turbine Building, El 137, Area 10		14	11/22/85
E-1926-1, Sh 1	Raceway Plan, Turbine Building, El 171, Area 10		8	11/22/85
E-3020-0, Sh A	Logic Diagram, Station Service Transformer Protection (4 sheets)		1	09/27/82
E-3030-0, Sh 1	Logic Diagram, Unit Protection		2	06/10/85
E-3030-0, Sh 2	Logic Diagram, Unit Protection		3	09/24/85
E-3031-0	Logic Diagram, Main Turbine Generator Excitation Control		3	04/01/85
E-3032-0	Logic Diagram, 13.8 kV Ring Bus Protection		0	09/16/82

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-3040-0	Logic Diagram, 7.2 kV Station Power System, Switchgear Main Circuit Breaker		10	11/01/85
E-3041-0	Logic Diagram, 7.2 kV Station Power System Bus Differential Overcurrent and Under Voltage Protection		3	10/19/83
E-3042-0	Logic Diagram, 7.2 kV Reactor Recirculation Motor-Generator Set Circuit Breaker		9	10/11/85
E-3043-0	Logic Diagram, Recirculation Pump Motor Circuit Breaker Control		3	10/25/84
E-3044-0	Logic Diagram, Station Power Switchgear Breaker Fail Relaying		1	02/17/84
E-3050-0, Sh 1	Logic Diagram, 4.16 kV Station Power System Switchgear Main Circuit Breaker		13	11/01/85
E-3050-0, Sh 2	Logic Diagram, 4.16 kV Station Power Switchgear Main Circuit Breaker Circuit Breaker		5	11/01/85
E-3051-0, Sh 1	Logic Diagram, 4.16 kV Station Power System Switchgear Unit Sub Transformer Feeder Circuit Breaker		10	11/01/85
E-3051-0, Sh 2	Logic Diagram 4.16 kV Station Power System Switchgear Unit Substation		5	11/01/85
E-3052-0, Sh 1	Logic Diagram 4.16 kV Station Power System Bus Differential Overcurrent and Undervoltage Protection.		2	11/23/82
E-3052-0, Sh 2	Logic Diagram, 4.16 kV Station Power System Bus Differential Overcurrent and Undervoltage Protection		2	11/23/82
E-3060-0	Logic Diagram, Class 1E Station Power Switchgear, 4.16 kV System Main Circuit Breaker		13	11/01/85
E-3061-0	Logic Diagram, Class 1E Switchgear 4.16 kV Unit Sub Transformer Feeder Circuit Breaker		6	11/01/85
E-3062-0, Sh 1	Logic Diagram 4.16 kV Class 1E BUS Differential Overcurrent and Undervoltage Protection		3	11/14/83
E-3062-0, Sh 2	Logic Diagram, 4.16 kV Class 1E BUS Differential Overcurrent and Undervoltage Protection		1	11/14/83
E-3065-0, Sh 1	Logic Diagram, Diesel Generator Regular & Backup Relaying		5	11/14/84
E-3065-0, Sh 2	Logic Diagram, Diesel Generator Regulatory & Backup Relaying		5	08/20/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-3080-0, Sh 1	Logic Diagram, Class 1E Switchgear, 4.16 kV System Diesel General Circuit Breaker		9	11/01/85
E-3080-0, Sh 2	Logic Diagram, Class 1E Switchgear, 4.16 kV System Diesel General Circuit Breaker		7	02/03/84
E-3081-0, Sh 1	Logic Diagram, Diesel Generator Control		5	03/17/84
E-3081-0, Sh 2	Logic Diagram, Diesel Generator Control		7	09/13/85
E-3090-0, Sh 1	Logic Diagram, 125 V dc System		6	05/15/85
E-3090-0, Sh 2	Logic Diagram, 125 V dc System		3	11/14/84
E-3110-0	Logic Diagram, 250 V Diesel Generator System		4	03/01/85
E-3120-0	Logic Diagram, 120 V ac Uninterruptible Power System Alarms		5	06/27/85
E-3132-0	Logic Diagram, Unit Substation 480 V System Motor Control Center and Feeder Circuit Breaker		5	09/17/84
E-3133-0, Sh 1	Logic Diagram, Unit Substation 480 V System Feeder Circuit Breaker, Non-1E Loads		5	10/25/84
E-3133-0, Sh 2	Logic Diagram, Unit Substation 480 V Feeder Circuit Breaker Non-IE Loads		4	06/14/85
E-3134-0	Logic Diagram, Unit Substation 480 V Feeder Circuit Breaker Alarm Input		7	10/25/84
E-3400-0, Sh 1	Logic Diagram, Electrical Distribution Alarm Input		4	11/18/83
E-3400-0, Sh 2	Logic Diagram, Electrical Distribution Alarm Input		2	11/18/83
E-3999-0, Sh A	Elec Loop Diagram, Transducers (12 sheets)		13	04/08/85
E-3999-0, Sh 11	Elec Loop Diagram, Circ Water Pump Motor Circuit Transducers		4	04/08/85
E-4068-1	Cable Block Diagram, Class 1E 4 kV Station Power Main Circuit Breaker		2	07/06/85
E-4069-1	CBD, Class 1E 4.16 kV Station Power Main Circuit Breaker 152-40101		2	07/16/85
E-4070-1	CBD, Class 1E 4.16 kV Station Power Main Circuit Breaker 152-40201		2	07/16/85
E-6001-0, Sh 1	ESD, Reactor Recirculation Motor-Generator Set Drive Motor, 7.2 kV Circuit Breaker		5	01/10/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-6001-0, Sh 2	ESD, Reactor Recirculator Motor-Generator Drive Motor, 7.2 kV Circuit Breaker and Motor-Generator Space Heaters		3	10/04/85
E-6016-0, Sh 1	ESD, Reactor Recirculation Pump, Motor Circuit Breaker Control Circuit		2	04/25/84
E-6016-0, Sh 2	ESD, Reactor Recirculation Pump, Motor Circuit Breaker Control		2	04/25/84
E-6022-0	ESD, Core Spray System, Core Spray Pump Suction Valves		3	12/19/84
E-6023-0	ESD, Core Spray System, Core Spray Isolation Valves		3	06/03/85
E-6024-0	ESD, Core Spray System, Core Spray Minimum Flow Valves		3	01/14/85
E-6025-0	ESD, Core Spray System, Core Spray Reactor Isolation Valves		3	07/24/84
E-6026-0	ESD, Core Spray System Core Spray Test Return Valves		4	12/19/84
E-6067-0, Sh A	ESD, Solenoid Pilot Valves "A" For Safety/Relief Valves DSV-F0135, F & K		3	04/30/84
E-6067-0, Sh 2	ESD, Solenoid Pilot Valves "A" for Safety/Relief Valves PSV-F013L & P		4	11/14/85
E-6067-0, Sh 4	ESD, Solenoid Pilot Valves "A" for Safety/Relief Valves PSV-F013H, F & M		4	11/14/85
E-6074-0	ESD, High Pressure Coolant Injection, Turbine Auxiliary Oil Pump (HPCI)		4	05/10/85
E-6074-1, Sh 1	ESD, HPCI Condensate & Vacuum Pump Motors		4	01/17/85
E-6074-1, Sh 2	ESD, HPCI Condensate and Vacuum Pump Motors		5	06/03/85
E-6082-1, Sh 1	ESD, RCIC System Pump Motors Vacuum & Condensate Pumps		4	01/17/85
E-6082-1, Sh 2	ESD, RCIC System Pump Motors Vacuum & Condensate Pumps		4	01/17/85
E-6086-0	ESD, RCIC Isolation Cooling System AOVs		3	05/18/84
E-6089-0	ESD, Recirculation System Turbine Monitoring Circuits in Remote Shutdown Panel		9	11/11/85
E-6107-0, Sh 1	ESD, Nuclear Steam Supply Shutoff System Reactor Water Cleanup Isolation Valve		2	04/30/84
E-6107-0, Sh 2	ESD, Nuclear Steam Supply System Reactor Water Cleanup Valve		2	04/30/84
E-6109-0, Sh 1	ESD, Nuclear Boiler Line Drain Isolation Valves		5	10/18/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-6109-0, Sh 2	ESD, Nuclear Boiler Main Steam Line Drain Isolation Valves		2	06/03/85
E-6231-0, Sh A	ESD, RHR System MOVs w/o RSP-Remote Panel (14 sheets)		12	09/26/85
E-6234-0, Sh A	ESD, RHR System with RSP		9	09/26/85
E-6235-0	ESD, RHR Testable Check Valve Bypass		6	09/28/85
E-6239-0	ESD, RHR Heat Exchanger Pressure & Level Control Solenoid Valves		2	09/26/85
E-6253-0, Sh A	ESD, Reactor Water Cleanup System MOVs		5	08/08/85
E-6402-0	ESD, Main Steam Stop Valves		1	05/18/84
E-6404-0, Sh A	ESD, RHR System BOP Valves		6	09/26/85
E-6404-0, Sh 3	ESD, RHR System Reactor Building Isolation Valve		4	04/18/85
E-6406-0	ESD, 480 V Circuit Breaker Control, Reactor Recirculation System Motor-Generator Set Lube Oil Pumps		1	05/18/84
E-6416-0	ESD, Reactor Water Cleanup System MOVs		2	04/01/85
E-6419-0	ESD, Reactor Protector System Control Rod Drive (CRD) Scram Discharge Volume Outboard Vent & Drain Vlvs Ind		1	10/19/83
E-6422-0	ESD, CRD Hydraulic Reactor Building Isolation Valve HV-4005		2	05/18/84
E-6431-0	ESD, HPCI Pump Turbine Emergency Core Cooling System Jockey Pump 1AP228		3	01/25/85
E-6433-0	ESD, Reactor Core Isolation Cooling System Pump Turbine Emergency Core Cooling System 1BP228		4	07/22/85
E-6435-0, Sh 1	ESD, RHR System Jockey Pump DP228		3	10/12/84
E-6435-0, Sh 2	ESD, RHR Jockey Pump ICP228		2	10/12/84
E-6439-0	ESD, HPCI Suppression Pool Isolation Valves		2	01/10/85
E-6440-0	ESD, HPCI Pump Turbine Vacuum Pump Discharge to Cond IHV-4922		2	04/19/84
E-6441-0, Sh 1	ESD, Class 1E 4.16 kV Circuit Breaker Control, RHR Pumps 1AP202, 1CP202, 1DP202		5	05/10/85
E-6441-0, Sh 2	ESD, 4.16 kV Circuit Breaker RHR Pump 1AP202, 1CP202, 1DP202		5	10/03/85

TABLE 1.7-1 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
E-6442-0	ESD, 4.16 kV Circuit Breaker Control, Core Spray Pumps		6	07/11/85
E-6443-0	ESD, 4.16 kV Circuit Breaker Control RHR Pump 1BP202		7	10/03/85
E-6531-0	ESD, 4 kV & 6.9 kV Motor Space Heaters		2	01/23/84
E-6603-0, Sh 1	RSP-10C399 Transfer Switch Contact UT Table		4	03/09/83

TABLE 1.7-2

FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number	System	FSAR Figure Number	Revision	Date
M-00-0, Sh 1	P&ID Legend	1.13-1	8	08/30/85
M-00-0, Sh 2	P&ID Legend	1.13-1	9	09/09/85
M-01-1	Main Steam	10.3-1	16	12/10/85
M-02-1	Extraction Steam	10.2-4	9	05/01/85
M-03-1	Vents & Drains Heaters 1&2		9	06/05/85
M-04-1	Vents & Drains Heaters 3,4,5,&6		9	09/09/85
M-05-1, Sh 1	Condensate	10.4-5	8	12/06/84
M-05-1, Sh 2	Condensate	10.4-5	10	11/08/85
M-05-1, Sh 3	Condensate	10.4-5	12	12/04/85
M-06-1	Feedwater	10.4-6	9	11/03/85
M-07-1	Condenser Air Removal	10.4-1	15	12/13/85
M-08-0, Sh 1	Condensate & Refueling Water Storage & Transfer	9.2-13	15	12/04/85
M-08-0, Sh 2	Condensate & Refueling Water Storage & Transfer	9.2-13	9	10/03/85
M-09-1, Sh 1	Circulating Water	10.4-3	11	11/15/85
M-09-1, Sh 2	Circulating Water	10.4-3	8	07/26/85
M-10-1, Sh 1	Service Water	9.2-2	11	12/04/85
M-10-1, Sh 2	Service Water	9.2-3	11	10/03/85
M-10-1, Sh 3	Service Water		8	10/11/85
M-11-1, Sh 1	Safety Auxiliaries Cooling, Reactor Building	9.2-4	11	07/25/85
M-11-1, Sh 2	Safety Auxiliaries Cooling, Reactor Building	9.2-4	12	11/15/85
M-11-1, Sh 3	Safety Auxiliaries Cooling, Reactor Building	9.2-4	5	10/03/85
M-12-1	Safety Auxiliaries Cooling, Auxiliary Building	9.2-5	9	12/30/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-13-0	Reactor Auxiliaries Cooling	9.2-16	10	05/01/85
M-13-1	Reactor Auxiliaries Cooling	9.2-17	12	11/26/85
M-14-1, Sh 1	Turbine Auxiliaries Cooling	9.2-6	9	11/03/85
M-14-1, Sh 2	Turbine Auxiliaries Cooling	9.2-6	11	11/08/85
M-15-0, Sh 1	Compressed Air	9.3-1	14	11/15/85
M-15-0, Sh 2	Compressed Air	9.3-2	14	12/30/85
M-15-0, Sh 3	Compressed Air		8	09/27/85
M-15-0, Sh 4	Compressed Air	9.3-3	8	02/01/85
M-15-0, Sh 5	Compressed Air		1	12/15/82
M-15-1	Breathing Air	9.5-32	8	11/08/85
M-16-1, Sh 1	Condensate Demineralizer	10.4-4	10	12/04/85
M-16-1, Sh 2	Condensate Demineralizer	10.4-4	9	11/03/85
M-17-0	Fresh Water Pretreatment	9.2-8	6	12/13/85
M-18-0, Sh 1	Demineralized Water Makeup Storage & Transfer	9.2-7	12	10/21/85
M-18-0, Sh 2	Demineralized Water Makeup Storage & Transfer	9.2-7	10	11/08/85
M-18-0, Sh 3	Demineralized Water Makeup Storage & Transfer	9.2-7	7	10/03/85
M-19-1, Sh 1	Lube Oil		10	12/04/85
M-19-1, Sh 2	Lube Oil		6	05/01/85
M-19-1, Sh 3	Lube Oil		10	11/08/85
M-19-1, Sh 4	Lube Oil		4	10/18/84
M-19-1, Sh 5	Lube Oil		5	11/03/85
M-19-1, Sh 6	Lube Oil		5	12/10/85
M-20-0, Sh 1	Auxiliary Boiler Fuel Oil System	9.5-31	7	12/10/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-20-0, Sh 2	Auxiliary Boiler Fuel Oil System	9.5-31	5	05/01/85
M-21-0, Sh 1	Auxiliary Steam	9.5-30	10	11/03/85
M-21-0, Sh 2	Auxiliary Steam	9.5-30	9	11/08/85
M-22-0, Sh 1	Fire Protection	9.5-13	18	12/30/85
M-22-0, Sh 2	Fire Protection	9.5-14	16	12/13/85
M-22-0, Sh 3	Fire Protection	9.5-15	13	12/30/85
M-22-0, Sh 4	Fire Protection	9.5-16	8	12/30/85
M-22-0, Sh 5	Fire Protection	9.5-17	11	11/26/85
M-22-0, Sh 6	Fire Protection	9.5-18	10	07/25/85
M-22-0, Sh 7	Fire Protection	9.5-19	8	12/30/85
M-23-0	Process Sampling	9.3-4	8	01/07/85
M-23-1, Sh 1	Process Sampling	9.3-4	9	11/26/85
M-23-1, Sh 2	Process Sampling	9.3-4	8	11/03/85
M-23-1, Sh 3	Process Sampling		B	06/05/75
M-23-1, Sh 4	Process Sampling		A	06/05/75
M-24-0, Sh 1	Circulating Water Hypochlorination		7	08/26/85
M-24-0, Sh 2	Circulating Water Acid Injection		6	06/14/85
M-24-0, Sh 3	Service Water Hypochlorination		8	11/18/85
M-24-0, Sh 4	Circulating Water Caustic and Scale Inhibitor Injection		2	11/08/85
M-25-1, Sh 1	Plant Leak Detection	11.5-3	5	11/26/85
M-25-1, Sh 2	Plant Leak Detection	11.5-3	4	11/03/85
M-25-1, Sh 3	Plant Leak Detection	11.5-3	4	11/03/85
M-26-1, Sh 1	Radiological Monitoring System	11.5-1	4	10/16/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-26-1, Sh 2	Radiological Monitoring System	11.5-1	3	10/16/85
M-27	Not used			
M-28-1	Generator Gas Control	10.2-3	8	11/18/85
M-29-1	Turbine Sealing Steam	10.4-2	9	07/28/85
M-30-1, Sh 1	Diesel Engine Auxiliary Systems	9.5-22	14	12/04/85
M-30-1, Sh 2	Diesel Engine Auxiliary Systems	9.5-25	8	10/21/85
M-30-1, Sh 3	Diesel Engine Auxiliary Systems	9.5-28	10	11/18/85
M-31-1, Sh 1	Reactor Feed Pump Turbine Steam System	10.4-7	5	03/07/85
M-31-1, Sh 2	Reactor Feed Pump Turbine Steam System	10.4-7	3	12/09/83
M-32	Not used		A	11/07/78
M-33-0	Low Volume & Oily, Wastewater Treatment	11.5-2	3	09/20/85
M-34	Not used			
M-35	Guardhouse Air Flow Diagram		2	12/13/85
M-36-0	Guardhouse Air Control Diagram		3	10/25/84
M-37-0	Guardhouse Chilled Water System		4	09/28/84
M-38-0, Sh 1	Post-accident Sampling System	9.3-5	4	09/24/85
M-38-0, Sh 2	Post-accident Sampling System	9.3-5	3	10/21/85
M-39	Not used			
M-40	Not used			
M-41-1, Sh 1	Nuclear Boiler	5.1-3	12	11/04/85
M-41-1, Sh 2	Nuclear Boiler	5.1-3	10	11/04/85
M-42-1, Sh 1	Nuclear Boiler Vessel Instrumentation	5.1-4	8	12/13/85
M-42-1, Sh 2	Nuclear Boiler Vessel Instrumentation	5.1-4	7	12/13/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-43-1, Sh 1	Reactor Recirculation System	5.4-2	12	12/13/85
M-43-1, Sh 2	Reactor Recirculation System	5.4-2	6	12/19/85
M-44-1	Reactor Water Cleanup	5.4-17	11	11/03/85
M-45-1	Cleanup Filter/Demineralizer	5.4-19	11	10/03/85
M-46-1	Control Rod Drive Hydraulic - Part A	4.6-5	9	06/27/85
M-47-1, Sh 1	Control Rod Drive Hydraulic - Part B	4.6-6	11	11/26/85
M-47-1, Sh 2	Control Rod Drive Hydraulic - Part B	4.6-6	2	05/05/85
M-48-1	Standby Liquid Control	9.3-8	8	11/03/85
M-49-1	Reactor Core Isolation Cooling	5.4-8	11	11/26/85
M-50-1	RCIC Pump Turbine	5.4-9	13	11/03/85
M-51-1, Sh 1	Residual Heat Removal	5.4-13	15	12/04/85
M-51-1, Sh 2	Residual Heat Removal	5.4-13	15	12/04/85
M-52-1	Core Spray	6.3-7	13	11/16/85
M-53-1, Sh 1	Fuel Pool Cooling & Torus Water Cleanup	9.1-5	15	12/10/85
M-53-1, Sh 2	Fuel Pool Cooling & Torus Water Cleanup	9.1-5	12	11/08/85
M-54-0	Fuel Pool Filter Demineralizer	9.1-6	9	12/19/85
M-55-1	High Pressure Coolant Injection	6.3-1	16	12/10/85
M-56-1	HPCI Pump Turbine	6.3-2	12	09/09/85
M-57-1	Containment Atmosphere Control	6.2-29	13	11/03/85
M-58-1	Containment Hydrogen Recombination System	6.2-30	5	11/03/85
M-59-1, Sh 1	Primary Containment Instrument Gas	9.3-11	10	11/04/85
M-59-1, Sh 2	Primary Containment Instrument Gas	9.3-11	5	11/26/85
M-60-1	Primary Containment Leakage Rate Testing	6.2-41	9	10/21/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-61-0	Equipment and Floor Drainage	9.3-7 sh 2 of 3	5	02/14/85
M-61-1, Sh 1	Equipment and Floor Drainage	9.3-7 sh 3 of 3	12	07/05/85
M-61-1, Sh 2	Equipment and Floor Drainage	9.3-7 sh 1 of 3	8	07/05/85
M-62-0, Sh 1	Liquid Radwaste Equipment Drain Processing	11.2-1	13	11/18/85
M-62-0, Sh 2	Liquid Radwaste Equipment Drain Processing	11.2-1	8	06/14/85
M-63-0, Sh 1	Liquid Radwaste Flood Drain Processing	11.2-2	12	11/18/85
M-63-0, Sh 2	Liquid Radwaste Flood Drain Processing	11.2-2	8	06/14/85
M-64-0	Liquid Radwaste Chemical Waste Processing	11.2-3	10	11/03/85
M-65-0, Sh 1	Liquid Radwaste Regenerant Waste Processing	11.2-4	9	08/30/85
M-65-0, Sh 2	Liquid Radwaste Regenerant Waste Processing	11.2-4	8	07/16/85
M-65-0, Sh 3	Liquid Radwaste Regenerant Waste Processing	11.2-4	7	11/03/85
M-66-0	Solid Radwaste Collection	11.4-1	12	12/30/85
M-67-0, Sh 1	Solid Radwaste Volume Reduction System	11.4-2	9	12/19/85
M-67-0, Sh 2	Solid Radwaste Volume Reduction System	11.4-3	7	12/19/85
M-68-0, Sh 1	Solid Radwaste Processing Solidification	11.4-4	6	09/27/85
M-68-0, Sh 2	Solid Radwaste Processing Solidification	11.4-5	6	09/27/85
M-68-0, Sh 3	Solid Radwaste Processing Solidification	11.4-6	7	08/13/85
M-68-0, Sh 4	Solid Radwaste Processing Solidification	11.4-7	8	08/20/85
M-68-0, Sh 5	Not used			
M-68-0, Sh 6	Not used			
M-68-0, Sh 7	Solid Radwaste Processing Solidification	11.4-8	3	12/10/85
M-68-0, Sh 8	Solid Radwaste Processing Solidification	11.4-9	6	11/03/85
M-69-0, Sh 1	Gaseous Radwaste Recombiner	11.3-2	12	11/08/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-69-0, Sh 2	Gaseous Radwaste Recombiner	11.3-3	9	12/10/85
M-69-0, Sh 3	Gaseous Radwaste Recombiner		2	11/03/85
M-70-0, Sh 1	Gaseous Radwaste Ambient Charcoal Treatment System	11.3-4	6	10/11/85
M-70-0, Sh 2	Gaseous Radwaste Ambient Charcoal Treatment System	11.3-5	4	07/08/85
M-70-0, Sh 3	Gaseous Radwaste Ambient Charcoal Treatment System		6	09/27/85
M-71-0	Liquid Nitrogen for Purge and Containment Inerting		3	09/09/85
M-72-1	Main Steam Isolation Valve Sealing System	6.7-1	6	11/26/85
M-73-0	Administration Facility Chilled Water		6	12/04/85
M-74-0	Administration Facility Control Diagram		7	12/04/85
M-75-1, Sh 1	Turbine Building Air Flow Diagram	9.4-11	12	12/04/85
M-75-1, Sh 2	Not used			
M-76-1	Reactor Building Air Flow Diagram	9.4-3	9	12/13/85
M-77-1	Drywell Air Flow Diagram	9.4-13	5	10/11/85
M-78-1	Auxiliary Building Control Area Air Flow Diagram	9.4-1	13	11/03/85
M-79-0, Sh 1	Technical Support Center Air Flow Diagram	9.4-7	12	12/30/85
M-79-0, Sh 2	Technical Support Center Air Flow Diagram	9.4-10	4	09/13/85
M-80-0	Administration Facility Air Flow Diagram		7	07/26/83
M-81-0, Sh 1	Service Water Intake Structure Miscellaneous Structures Air Flow Diagrams	9.4-17	5	03/28/83
M-81-0, Sh 2	Miscellaneous Structures and Yard Buildings Air Flow Diagrams	9.4-19	6	11/03/85
M-81-0, Sh 3	Miscellaneous Structures and Yard Buildings Air Flow Diagrams		5	12/17/82
M-82-1, Sh 1	Turbine Building Supply & Exhaust Control Diagram	9.4-12	13	10/21/85
M-82-1, Sh 2	Not used			

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-83-1	Reactor Building Supply Control Diagram	9.4-4	11	07/25/85
M-84-1	Reactor Building Exhaust Control Diagram	9.4-5	13	12/10/85
M-85-1, Sh 1	Auxiliary Building Diesel Area Air Flow Diagram	9.4-15	11	09/27/85
M-85-1, Sh 2	Auxiliary Building Diesel Area Air Flow Diagram	9.4-15	6	09/27/85
M-86-1	Drywell Control Diagram	9.4-14	4	10/21/85
M-87-1, Sh 1	Chilled Water System	9.2-14	11	11/26/85
M-87-1, Sh 2	Chilled Water System	9.2-14	11	12/04/85
M-87-1, Sh 3	Chilled Water System	9.2-14	7	11/03/85
M-87-1, Sh 4	Chilled Water System	9.2-14	8	12/04/85
M-88-1, Sh 1	Auxiliary Building Diesel Area Control Diagram	9.4-16	10	12/10/85
M-88-1, Sh 2	Auxiliary Building Diesel Area Control Diagram	9.4-16	5	12/13/85
M-89-1	Auxiliary Building Control Area Control Diagram	9.4-2	14	12/19/85
M-90-1, Sh 1	Auxiliary Building Control Area Chilled Water System	9.2-15	11	12/10/85
M-90-1, Sh 2	Auxiliary Building Control Area Chilled Water System	9.2-15	11	12/10/85
M-90-1, Sh 3	Auxiliary Building Control Area Chilled Water System	9.2-15	7	12/10/85
M-91-0, Sh 1	Auxiliary Building Radwaste Area Air Flow Diagram	9.4-6	13	11/26/85
M-91-0, Sh 2	Auxiliary Building Radwaste Area Air Flow Diagram	9.4-6	6	12/14/84
M-91-0, Sh 3	Auxiliary Building Radwaste Area Air Flow Diagram	9.4-6	3	11/08/85
M-92-0, Sh 1	Auxiliary Building Radwaste Area Control Diagrams	9.4-9	12	10/21/85
M-92-0, Sh 2	Auxiliary Building Radwaste Area Control Diagrams	9.4-9	2	12/19/85
M-93-0, Sh 1	Auxiliary Building Service Area Control Diagram	9.4-8	11	12/19/85
M-93-0, Sh 2	Technical Support Center Control Diagram	9.4-8	5	10/21/85
M-94-0	Roof Drainage System		4	11/18/85

TABLE 1.7-2 (Cont)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-95-0	Miscellaneous Structures & Yard Buildings Control Diagram	9.4-18	12	12/30/85
M-96-0, Sh 1	Plant Heating		12	12/04/85
M-96-0, Sh 2	Plant Heating		13	11/26/85
M-96-0, Sh 3	Plant Heating		9	11/26/84
M-97-0, Sh 1	Building & Equipment Drains, Aux Bldg, Radwaste Sys El 54'	9.3-12	6	10/21/85
M-97-0, Sh 2	Building & Equipment Drains, Aux Bldg Control & Diesel Areas; Chemical Waste Systems	9.3-12	9	12/04/85
M-97-0, Sh 3	Building & Equipment Drains, Aux Bldg Radwaste Sys Floor El 66'-0" to 172'-3"	9.3-12	6	10/21/85
M-97-0, Sh 4	Building & Equipment Drains, Aux Bldg Radwaste Sys Floor El 65'-0" to 153'-0"	9.3-12	6	11/08/85
M-97-0, Sh 5	Building & Equipment Drains, Intake Structure	9.3-13	2	4/16/85
M-97-1, Sh 1	Building & Equipment Drains, Turbine Bldg Floor El 54'-0" to 102'-0"	9.3-14, Sh 1 of 4	4	11/04/85
M-97-1, Sh 2	Building & Equipment Drains, Reactor Bldg	9.3-15	5	11/03/85
M-97-1, Sh 3	Building & Equipment Drains, Turbine Bldg Floor El 120'-0" to 188'-6"	9.3-14, Sh 2 of 4	5	07/14/85
M-97-2, Sh 1	Floor and Equipment Drains, Turbine Building	9.3-14,Sh 3 of 4	5	10/21/85
M-97-2, Sh 2	Not used			
M-97-2, Sh 3	Building Drains, Turbine Building Fl. El. 120'-0" to 171'-0"	9.3-14, 4 of 4	1	06/05/85
M-98-0, Sh 1	Domestic Water System	9.2-10	9	11/08/85
M-98-0, Sh 2	Domestic Water System	9.2-9	7	11/03/85
M-99-0, Sh 1	Building Sewage	9.2-11	3	11/11/85
M-99-0, Sh 2	Building Sewage	9.2-11	3	11/03/85
M-5001	Fire Protection & Detection Plan, El 54'0"		8	11/05/85

TABLE 1.7-2 (Cont.)

P&ID Number	System	FSAR Figure Number	Revision	Date
M-5002	Fire Protection & Detection Plan, El 77'-0"		8	11/05/85
M-5003	Fire Protection & Detection Plan, El 102'-0"		9	11/05/85
M-5004	Fire Protection & Detection Plan, El 120'-0" & 132'-0"		8	11/05/85
M-5005	Fire Protection & Detection Plan, El 137'-0" & 145'-0"		9	11/05/85
M-5006	Fire Protection & Detection Plan, El 155'-3" & 163'-6"		7	11/05/85
M-5007	Fire Protection & Detection Plan, El 171'-0" & 178'-0" & 201'-0"		8	11/05/85
M-5008	Fire Protection & Detection Section A-A & B-B		4	09/09/85
M-5009	Fire Protection & Detection Section C-C & D-D		4	09/09/85
M-5010	Fire Protection & Detection Section E-E & F-F		4	09/09/85
M-5011	Fire Protection & Detection Intake Structure Plan, El 93',100',114', & 122'		7	11/05/85
M-5012	Fire Protection & Detection Intake Structure Plan, El 93',107' and Sections		6	11/05/85
M-5013	Fire Protection & Detection Auxiliary Boiler, Circulating Water Structure & Fire Pump House		0	07/23/84

TABLE 1.7-3

CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-00-0	Standard Symbols		10	08/29/85
J-01-0, Sh 1	Main Steam		6	12/16/83
J-01-0, Sh 2	Main Steam		5	12/16/83
J-01-0, Sh 3	Main Steam		2	06/14/82
J-01-0, Sh 4	Main Steam		2	06/14/82
J-01-0, Sh 5	Main Steam		5	12/16/83
J-01-0, Sh 6	Main Steam		5	12/16/83
J-01-0, Sh 7	Main Steam		3	06/14/82
J-01-0, Sh 8	Main Steam		5	12/16/83
J-01-0, Sh 9	Main Steam		3	06/14/82
J-01-0, Sh 10	Main Steam		5	12/16/83
J-01-0, Sh 11	Main Steam		4	06/14/82
J-01-0, Sh 12	Main Steam		4	06/14/82
J-01-0, Sh 13	Main Steam		2	06/14/82
J-01-0, Sh 14	Main Steam		3	06/14/82
J-01-0, Sh 15	Main Steam		1	10/17/80
J-02-0, Sh 1	Extraction Steam		9	11/08/85
J-02-0, Sh 2	Extraction Steam		4	11/08/82
J-02-0, Sh 3	Extraction Steam		5	11/08/82
J-02-0, Sh 4	Extraction Steam		3	12/06/82
J-02-0, Sh 5	Extraction Steam		7	11/08/85
J-02-0, Sh 6	Extraction Steam		4	11/08/82
J-02-0, Sh 7	Extraction Steam		6	09/30/85
J-02-0, Sh 8	Extraction Steam		6	11/08/82
J-02-0, Sh 9	Extraction Steam		6	08/04/83
J-02-0, Sh 10	Extraction Steam		3	08/04/83
J-02-0, Sh 11	Extraction Steam		1	08/04/83
J-03-0, Sh 1	Vents and Drains, Heaters 1 & 2		5	06/14/82
J-03-0, Sh 2	Vents and Drains, Heaters 1 & 2		4	06/14/82
J-03-0, Sh 3	Vents and Drains, Heaters 1 & 2		3	06/14/82
J-03-0, Sh 4	Vents and Drains, Heaters 1 & 2		4	06/14/82
J-03-0, Sh 5	Vents and Drains, Heaters 1 & 2		5	06/14/82
J-04-0, Sh 1	Vents and Drains, Heaters 3, 4, 5, 6		6	08/30/83
J-04-0, Sh 2	Vents and Drains, Heaters 3, 4, 5, 6		4	06/14/82
J-04-0, Sh 3	Vents and Drains, Heaters 3, 4, 5, 6		5	06/14/82
J-04-0, Sh 4	Vents and Drains, Heaters 3, 4, 5, 6		5	06/14/82
J-04-0, Sh 5	Vents and Drains, Heaters 3, 4, 5, 6		5	06/14/82
J-04-0, Sh 6	Vents and Drains, Heaters 3, 4, 5, 6		2	06/14/82
J-04-0, Sh 7	Vents and Drains, Heaters 3, 4, 5, 6		5	06/14/82
J-04-0, Sh 8	Vents and Drains, Heaters 3, 4, 5, 6		6	08/30/83
J-04-0, Sh 9	Vents and Drains, Heaters 3, 4, 5, 6		5	06/14/82

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-05-0, Sh 1	Condensate System		10	10/02/85
J-05-0, Sh 2	Condensate System		7	10/02/85
J-05-0, Sh 3	Condensate System		6	10/02/85
J-05-0, Sh 4	Condensate System		3	06/14/82
J-05-0, Sh 5	Condensate System		8	10/02/85
J-05-0, Sh 6	Condensate System		3	06/18/82
J-05-0, Sh 7	Condensate System		5	11/05/84
J-05-0, Sh 8	Condensate System		5	04/18/83
J-05-0, Sh 9	Condensate System		4	06/14/82
J-05-0, Sh 10	Condensate System		6	11/05/84
J-05-0, Sh 11	Condensate System		4	06/14/82
J-05-0, Sh 12	Condensate System		5	11/05/84
J-05-0, Sh 13	Condensate System		4	06/14/82
J-05-0, Sh 14	Condensate System		7	11/05/84
J-05-0, Sh 15	Condensate System		6	11/05/84
J-05-0, Sh 16	Condensate System		1	06/14/82
J-05-0, Sh 17	Condensate System		1	06/14/82
J-05-0, Sh 18	Condensate System		2	11/05/84
J-06-0, Sh 1	Feedwater System		10	06/05/85
J-06-0, Sh 2	Feedwater System		4	06/07/82
J-06-0, Sh 3	Feedwater System		6	04/11/84
J-06-0, Sh 4	Feedwater System		3	06/07/82
J-06-0, Sh 5	Feedwater System		6	06/05/85
J-06-0, Sh 6	Feedwater System		6	12/16/83
J-06-0, Sh 7	Feedwater System		5	12/16/83
J-06-0, Sh 8	Feedwater System		1	06/07/82
J-07-0, Sh 1	Condenser Air Removal System		11	11/22/85
J-07-0, Sh 2	Condenser Air Removal System		3	06/11/82
J-07-0, Sh 3	Condenser Air Removal System		3	06/11/82
J-07-0, Sh 4	Condenser Air Removal System		3	06/11/82
J-07-0, Sh 5	Condenser Air Removal System		2	06/11/82
J-07-0, Sh 6	Condenser Air Removal System		3	06/11/83
J-07-0, Sh 7	Condenser Air Removal System		3	11/06/82
J-07-0, Sh 8	Condenser Air Removal System		2	06/11/82
J-07-0, Sh 9	Condenser Air Removal System		6	05/15/83
J-07-0, Sh 10	Condenser Air Removal System		9	11/22/85
J-07-0, Sh 11	Condenser Air Removal System		4	05/15/83
J-07-0, Sh 12	Condenser Air Removal System		7	01/12/84
J-07-0, Sh 13	Condenser Air Removal System		1	01/12/84
J-08-0, Sh 1	Condensate & Refueling Water Storage & Transfer		13	11/04/85
J-08-0, Sh 2	Condensate & Refueling Water Storage & Transfer		6	11/04/85
J-08-0, Sh 3	Condensate & Refueling Water Storage & Transfer		6	11/04/85
J-08-0, Sh 4	Condensate & Refueling Water Storage & Transfer		5	12/03/84

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-08-0, Sh 5	Condensate & Refueling Water Storage & Transfer		3	06/15/82
J-08-0, Sh 6	Condensate & Refueling Water Storage & Transfer		8	12/03/84
J-08-0, Sh 7	Condensate & Refueling Water Storage & Transfer		4	06/15/82
J-08-0, Sh 8	Condensate & Refueling Water Storage & Transfer		11	12/03/84
J-08-0, Sh 9	Condensate & Refueling Water Storage & Transfer		6	11/04/85
J-08-0, Sh 10	Condensate & Refueling Water Storage & Transfer		7	12/03/84
J-08-0, Sh 11	Condensate & Refueling Water Storage & Transfer		2	08/27/80
J-09-0, Sh 1	Circulating Water System		8	11/04/85
J-09-0, Sh 2	Circulating Water System		7	11/04/85
J-09-0, Sh 3	Circulating Water System		4	06/14/82
J-09-0, Sh 4	Circulating Water System		5	02/13/84
J-09-0, Sh 5	Circulating Water System		4	12/03/84
J-09-0, Sh 6	Circulating Water System		5	02/13/84
J-09-0, Sh 7	Circulating Water System		7	11/04/85
J-09-0, Sh 8	Circulating Water System		4	02/13/84
J-09-0, Sh 9	Circulating Water System		5	02/13/84
J-09-0, Sh 10	Circulating Water System		5	02/13/84
J-09-0, Sh 11	Circulating Water System		5	02/13/84
J-09-0, Sh 12	Circulating Water System		5	02/12/84
J-09-0, Sh 13	Circulating Water System		5	02/13/84
J-09-0, Sh 14	Circulating Water System		4	02/13/84
J-09-0, Sh 15	Circulating Water System		3	06/14/82
J-09-0, Sh 16	Circulating Water System		8	11/04/85
J-09-0, Sh 17	Circulating Water System		7	12/03/84
J-09-0, Sh 18	Circulating Water System		3	02/13/84
J-09-0, Sh 19	Circulating Water System		1	06/14/82
J-09-0, Sh 20	Circulating Water System		2	02/13/84
J-09-0, Sh 21	Circulating Water System		2	02/13/84
J-10-0, Sh 1	Station Service Water System	7.3-20	13	12/10/85
J-10-0, Sh 2	Station Service Water System		9	09/16/84
J-10-0, Sh 3	Station Service Water System		7	05/02/83
J-10-0, Sh 4	Station Service Water System		9	09/16/84
J-10-0, Sh 5	Station Service Water System		8	12/10/85
J-10-0, Sh 6	Station Service Water System		9	09/16/84
J-10-0, Sh 7	Station Service Water System		8	05/02/83
J-10-0, Sh 8	Station Service Water System		7	09/16/84
J-10-0, Sh 9	Station Service Water System		7	09/16/84
J-10-0, Sh 10	Station Service Water System		8	09/16/84
J-10-0, Sh 11	Station Service Water System		7	09/16/84
J-10-0, Sh 12	Station Service Water System		4	12/12/83
J-10-0, Sh 13	Station Service Water System		8	09/16/84
J-10-0, Sh 14	Station Service Water System		9	12/10/85
J-10-0, Sh 15	Station Service Water System		10	09/16/84

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-10-0, Sh 16	Station Service Water System		8	09/16/84
J-10-0, Sh 17	Station Service Water System		8	09/16/84
J-10-0, Sh 18	Station Service Water System		8	09/16/84
J-10-0, Sh 19	Station Service Water System		7	05/02/83
J-10-0, Sh 20	Station Service Water System		7	09/16/84
J-10-0, Sh 21	Station Service Water System		3	12/10/85
J-10-0, Sh 22	Station Service Water System		5	12/10/85
J-10-0, Sh 23	Station Service Water System		8	09/16/84
J-10-0, Sh 24	Station Service Water System		7	08/30/83
J-10-0, Sh 25	Station Service Water System		5	09/16/84
J-10-0, Sh 26	Station Service Water System		4	12/10/85
J-10-0, Sh 27	Station Service Water System		4	12/10/85
J-10-0, Sh 28	Station Service Water System		1	06/17/82
J-10-0, Sh 29	Station Service Water System		2	09/16/84
J-10-0, Sh 30	Station Service Water System		3	09/16/84
J-10-0, Sh 31	Station Service Water System		3	12/10/85
J-11-0, Sh 1	Safety Auxiliaries Cooling	7.3-21	11	10/07/85
J-11-0, Sh 2	Safety Auxiliaries Cooling		7	10/07/85
J-11-0, Sh 3	Safety Auxiliaries Cooling		5	10/07/85
J-11-0, Sh 4	Safety Auxiliaries Cooling		7	10/07/85
J-11-0, Sh 5	Safety Auxiliaries Cooling		6	10/07/85
J-11-0, Sh 6	Safety Auxiliaries Cooling		6	10/18/84
J-11-0, Sh 7	Safety Auxiliaries Cooling		6	10/07/85
J-11-0, Sh 8	Safety Auxiliaries Cooling		6	10/07/85
J-11-0, Sh 9	Safety Auxiliaries Cooling		5	10/17/84
J-11-0, Sh 10	Safety Auxiliaries Cooling		1	01/05/79
J-11-0, Sh 11	Safety Auxiliaries Cooling		1	01/05/79
J-11-0, Sh 12	Safety Auxiliaries Cooling		4	08/06/82
J-11-0, Sh 13	Safety Auxiliaries Cooling		4	08/06/82
J-11-0, Sh 14	Safety Auxiliaries Cooling		3	10/17/84
J-11-0, Sh 15	Safety Auxiliaries Cooling		5	10/18/84
J-11-0, Sh 16	Safety Auxiliaries Cooling		7	10/07/85
J-11-0, Sh 17	Safety Auxiliaries Cooling		4	04/18/83
J-11-0, Sh 18	Safety Auxiliaries Cooling		5	10/17/84
J-11-0, Sh 19	Safety Auxiliaries Cooling		6	10/07/85
J-11-0, Sh 20	Safety Auxiliaries Cooling		4	08/06/82
J-11-0, Sh 21	Safety Auxiliaries Cooling		6	10/07/85
J-11-0, Sh 22	Safety Auxiliaries Cooling		8	10/17/84
J-11-0, Sh 23	Safety Auxiliaries Cooling		4	10/17/84
J-11-0, Sh 24	Safety Auxiliaries Cooling		5	10/17/84
J-11-0, Sh 25	Safety Auxiliaries Cooling		4	04/18/83
J-11-0, Sh 26	Safety Auxiliaries Cooling		3	10/17/84
J-11-0, Sh 27	Safety Auxiliaries Cooling		6	07/23/84

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-11-0, Sh 28	Safety Auxiliaries Cooling		3	08/06/82
J-11-0, Sh 29	Safety Auxiliaries Cooling		3	10/07/85
J-11-0, Sh 30	Safety Auxiliaries Cooling		4	10/17/84
J-11-0, Sh 31	Safety Auxiliaries Cooling		2	04/18/83
J-11-0, Sh 32	Safety Auxiliaries Cooling		2	04/18/83
J-11-0, Sh 33	Safety Auxiliaries Cooling		3	10/17/84
J-13-0, Sh 1	Reactor Auxiliaries Cooling		11	09/05/84
J-13-0, Sh 2	Reactor Auxiliaries Cooling		6	10/29/82
J-13-0, Sh 3	Reactor Auxiliaries Cooling		5	10/29/82
J-13-0, Sh 4	Reactor Auxiliaries Cooling		6	09/05/84
J-13-0, Sh 5	Reactor Auxiliaries Cooling		6	09/05/84
J-13-0, Sh 6	Reactor Auxiliaries Cooling		9	09/05/84
J-13-0, Sh 7	Reactor Auxiliaries Cooling		5	05/23/83
J-13-0, Sh 8	Reactor Auxiliaries Cooling		4	10/29/82
J-13-0, Sh 9	Reactor Auxiliaries Cooling		6	09/05/84
J-13-0, Sh 10	Reactor Auxiliaries Cooling		5	10/29/82
J-13-0, Sh 11	Reactor Auxiliaries Cooling		8	09/05/84
J-13-0, Sh 12	Reactor Auxiliaries Cooling		7	08/25/83
J-13-0, Sh 13	Reactor Auxiliaries Cooling		3	12/16/83
J-13-0, Sh 14	Reactor Auxiliaries Cooling		2	12/16/83
J-13-0, Sh 15	Reactor Auxiliaries Cooling		0	10/29/82
J-14-0	Turbine Auxiliary Cooling		3	01/04/84
H-15-0	Compressed Air System		7	10/22/85
J-15-0, Sh 1	Breathing Air System		2	05/18/84
J-15-0, Sh 2	Breathing Air System		0	05/23/83
J-15-0, Sh 3	Breathing Air System		2	05/18/84
J-15-0, Sh 4	Breathing Air System		1	12/22/83
J-16-0, Sh 1	Condensate Demineralizer		5	04/18/83
J-16-0, Sh 2	Condensate Demineralizer		4	04/18/83
J-17-0, Sh 1	Fresh Water Supply		2	12/16/83
J-17-0, Sh 2	Fresh Water Supply		1	12/16/83
J-17-0, Sh 3	Fresh Water Supply		0	11/18/82
J-17-0, Sh 4	Fresh Water Supply		0	11/18/82
J-17-0, Sh 5	Fresh Water Supply		2	12/16/83
J-18-0, Sh 1	Demineralized Water Makeup Storage & Transfer		7	10/17/84
J-18-0, Sh 2	Demineralized Water Makeup Storage & Transfer		3	05/28/82
J-18-0, Sh 3	Demineralized Water Makeup Storage & Transfer		3	05/28/82
J-18-0, Sh 4	Demineralized Water Makeup Storage & Transfer		4	12/16/83
J-18-0, Sh 5	Demineralized Water Makeup Storage & Transfer		5	10/17/84
J-19-0, Sh 1	Lube Oil		9	05/10/85
J-19-0, Sh 2	Lube Oil		7	05/02/83
J-19-0, Sh 3	Lube Oil		5	06/21/82
J-19-0, Sh 4	Lube Oil		8	05/10/85

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-19-0, Sh 5	Lube Oil		5	05/10/85
J-19-0, Sh 6	Lube Oil		1	06/21/82
J-19-0, Sh 7	Lube Oil		2	06/21/82
J-19-0, Sh 8	Lube Oil		5	05/10/85
J-19-0, Sh 9	Lube Oil		5	05/02/83
J-19-0, Sh 10	Lube Oil		6	05/10/85
J-19-0, Sh 11	Lube Oil		6	05/10/85
J-19-0, Sh 12	Lube Oil		6	05/02/83
J-19-0, Sh 13	Lube Oil		6	05/10/85
J-19-0, Sh 14	Lube Oil		5	05/10/85
J-19-0, Sh 15	Lube Oil		6	05/10/85
J-20-0, Sh 1	Auxiliary Boiler Fuel Oil System		7	01/22/85
J-20-0, Sh 2	Auxiliary Boiler Fuel Oil System		6	05/11/84
J-20-0, Sh 3	Auxiliary Boiler Fuel Oil System		2	01/22/85
J-20-0, Sh 4	Auxiliary Boiler Fuel Oil System		1	06/02/83
J-21-0	Auxiliary Steam		1	06/02/83
H-22-0	Fire Protection - Fire Water		10	12/08/83
J-25-0, Sh 1	Plant Leak Detection		4	04/26/83
J-25-0, Sh 2	Plant Leak Detection		4	04/26/83
J-25-0, Sh 3	Plant Leak Detection		3	04/26/83
J-25-0, Sh 4	Plant Leak Detection		4	04/26/83
J-25-0, Sh 5	Plant Leak Detection		3	04/26/83
J-25-0, Sh 6	Plant Leak Detection		3	04/26/83
J-25-0, Sh 7	Plant Leak Detection		1	04/26/83
J-25-0, Sh 8	Plant Leak Detection		0	04/26/83
J-25-0, Sh 9	Plant Leak Detection		0	04/26/83
J-25-0, Sh 10	Plant Leak Detection		0	04/26/83
J-25-0, Sh 11	Plant Leak Detection		0	04/26/83
J-25-0, Sh 12	Plant Leak Detection		0	04/26/83
J-26-0, Sh 1	Radiation Monitoring System		1	10/12/84
J-26-0, Sh 2	Radiation Monitoring System		1	10/12/84
J-26-0, Sh 3	Radiation Monitoring System		1	10/12/84
J-28-0, Sh 1	Generator Gas Control		6	12/16/83
J-28-0, Sh 2	Generator Gas Control		3	12/16/83
J-29-0, Sh 1	Turbine Sealing Steam		7	04/26/83
J-29-0, Sh 2	Turbine Sealing Steam		4	06/21/82
J-29-0, Sh 3	Turbine Sealing Steam		4	06/21/82
J-29-0, Sh 4	Turbine Sealing Steam		3	06/21/82
J-29-0, Sh 5	Turbine Sealing Steam		5	06/21/82
J-29-0, Sh 6	Turbine Sealing Steam		2	06/21/82
J-29-0, Sh 7	Turbine Sealing Steam		5	04/26/83
J-30-0, Sh 1	Diesel Engine Auxiliary Systems		2	04/29/82
J-30-0, Sh 2	Diesel Engine Auxiliary Systems		1	04/29/83

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-30-0, Sh 3	Diesel Engine Auxiliary Systems		1	04/29/82
J-31-0, Sh 1	Reactor Feed Pump Turbine Steam System		9	06/24/85
J-31-0, Sh 2	Reactor Feed Pump Turbine Steam System		5	12/14/83
J-31-0, Sh 3	Reactor Feed Pump Turbine Steam System		4	09/11/84
J-31-0, Sh 4	Reactor Feed Pump Turbine Steam System		4	12/14/83
J-31-0, Sh 5	Reactor Feed Pump Turbine Steam System		8	06/24/85
J-31-0, Sh 6	Reactor Feed Pump Turbine Steam System		7	06/24/85
J-31-0, Sh 7	Reactor Feed Pump Turbine Steam System		7	06/24/85
J-31-0, Sh 8	Reactor Feed Pump Turbine Steam System		7	09/11/84
J-31-0, Sh 9	Reactor Feed Pump Turbine Steam System		6	12/14/83
J-31-0, Sh 10	Reactor Feed Pump Turbine Steam System		5	08/26/83
J-31-0, Sh 11	Reactor Feed Pump Turbine Steam System		6	06/24/85
J-31-0, Sh 12	Reactor Feed Pump Turbine Steam System		5	12/14/83
J-31-0, Sh 13	Reactor Feed Pump Turbine Steam System		6	09/11/84
J-31-0, Sh 14	Reactor Feed Pump Turbine Steam System		5	08/26/83
J-31-0, Sh 15	Reactor Feed Pump Turbine Steam System		3	12/14/83
J-31-0, Sh 16	Reactor Feed Pump Turbine Steam System		3	12/14/83
J-31-0, Sh 17	Reactor Feed Pump Turbine Steam System		3	12/14/83
J-31-0, Sh 18	Reactor Feed Pump Turbine Steam System		0	08/26/83
J-38-0, Sh 1	Post Accident Sampling System	9.3-6	1	10/24/84
J-38-0, Sh 2	Post Accident Sampling System		1	10/24/84
J-41-0, Sh 1	Nuclear Boiler	7.3-4	9	11/06/85
J-41-0, Sh 2	Nuclear Boiler		5	11/06/85
J-41-0, Sh 3	Nuclear Boiler		7	08/30/84
J-41-0, Sh 4	Nuclear Boiler		5	08/30/84
J-41-0, Sh 5	Nuclear Boiler		5	04/04/83
J-41-0, Sh 6	Nuclear Boiler		5	08/30/84
J-41-0, Sh 7	Nuclear Boiler		3	06/19/82
J-41-0, Sh 8	Nuclear Boiler		3	06/19/82
J-41-0, Sh 9	Nuclear Boiler		4	08/30/84
J-41-0, Sh 10	Nuclear Boiler		2	06/19/82
J-41-0, Sh 11	Nuclear Boiler		4	12/10/83
J-41-0, Sh 12	Nuclear Boiler		4	12/10/83
J-41-0, Sh 13	Nuclear Boiler		5	11/06/85
J-41-0, Sh 14	Nuclear Boiler		3	08/30/84
J-41-0, Sh 15	Nuclear Boiler		3	11/06/85
J-41-0, Sh 16	Nuclear Boiler		2	11/06/85
J-41-0, Sh 16A	Nuclear Boiler		0	11/06/85
J-42-0, Sh 2	Nuclear Boiler Vessel Instrumentation		5	12/05/83
J-42-0, Sh 3	Nuclear Boiler Vessel Instrumentation		4	12/05/83
J-42-0, Sh 4	Nuclear Boiler Vessel Instrumentation		2	06/14/82
J-42-0, Sh 5	Nuclear Boiler Vessel Instrumentation		5	12/05/83
J-43-0, Sh 1	Reactor Recirculation System		13	11/04/85

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-43-0, Sh 2	Reactor Recirculation System		8	11/04/85
J-43-0, Sh 3	Reactor Recirculation System		7	11/04/85
J-43-0, Sh 4	Reactor Recirculation System		8	06/24/85
J-43-0, Sh 5	Reactor Recirculation System		3	---
J-43-0, Sh 6	Reactor Recirculation System		5	10/12/84
J-43-0, Sh 7	Reactor Recirculation System		4	06/21/83
J-43-0, Sh 8	Reactor Recirculation System		4	10/12/84
J-43-0, Sh 9	Reactor Recirculation System		7	11/04/85
J-43-0, Sh 10	Reactor Recirculation System		1	06/21/83
J-44-0, Sh 1	Reactor Water Cleanup		11	10/29/85
J-44-0, Sh 2	Reactor Water Cleanup		7	10/29/85
J-44-0, Sh 3	Reactor Water Cleanup		6	08/30/84
J-44-0, Sh 4	Reactor Water Cleanup		6	08/30/84
J-44-0, Sh 5	Reactor Water Cleanup	7.3-10	5	08/30/84
J-44-0, Sh 6	Reactor Water Cleanup		3	12/14/83
J-44-0, Sh 7	Reactor Water Cleanup		4	12/14/83
J-44-0, Sh 8	Reactor Water Cleanup		2	12/14/83
J-45-0, Sh 1	Cleanup Filter/Demineralizer		2	12/10/83
J-45-0, Sh 2	Cleanup Filter/Demineralizer		1	08/30/84
J-46-0, Sh 1	Control Rod Drive Hydraulic		7	02/11/85
J-46-0, Sh 2	Control Rod Drive Hydraulic		6	12/10/83
J-46-0, Sh 3	Control Rod Drive Hydraulic		5	12/10/83
J-46-0, Sh 4	Control Rod Drive Hydraulic		3	06/14/82
J-46-0, Sh 5	Control Rod Drive Hydraulic		3	06/14/82
J-46-0, Sh 6	Control Rod Drive Hydraulic		4	02/11/85
J-46-0, Sh 7	Control Rod Drive Hydraulic		2	02/11/85
J-46-0, Sh 8	Control Rod Drive Hydraulic		3	06/14/83
J-46-0, Sh 9	Control Rod Drive Hydraulic		3	06/14/83
J-47-0, Sh 1	Control Rod Drive Hydraulic - Part B		2	12/05/83
J-47-0, Sh 2	Control Rod Drive Hydraulic - Part B		2	12/05/83
J-47-0, Sh 3	Control Rod Drive Hydraulic - Part B		2	12/05/83
J-48-0, Sh 1	Standby Liquid Control	7.4-4	7	11/01/85
J-48-0, Sh 2	Standby Liquid Control	7.4-4	7	11/01/85
J-48-0, Sh 3	Standby Liquid Control		5	11/01/85
J-48-0, Sh 4	Standby Liquid Control		3	05/24/83
J-48-0, Sh 5	Standby Liquid Control		1	12/14/83
J-49-0, Sh 1	Reactor Core Isolation Cooling System	7.4-2	13	12/10/85
J-49-0, Sh 2	Reactor Core Isolation Cooling System		8	12/10/85
J-49-0, Sh 3	Reactor Core Isolation Cooling System		4	09/11/84
J-49-0, Sh 4	Reactor Core Isolation Cooling System		4	09/11/84
J-49-0, Sh 5	Reactor Core Isolation Cooling System		6	10/01/85
J-49-0, Sh 5A	Reactor Core Isolation Cooling System		2	10/01/85
J-49-0, Sh 6	Reactor Core Isolation Cooling System		6	12/10/85

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-49-0, Sh 7	Reactor Core Isolation Cooling System		7	12/10/85
J-49-0, Sh 8	Reactor Core Isolation Cooling System		4	09/11/84
J-49-0, Sh 9	Reactor Core Isolation Cooling System		6	06/24/85
J-49-0, Sh 10	Reactor Core Isolation Cooling System		3	06/16/82
J-49-0, Sh 11	Reactor Core Isolation Cooling System		2	06/16/82
J-49-0, Sh 12	Reactor Core Isolation Cooling System		4	10/01/85
J-49-0, Sh 13	Reactor Core Isolation Cooling System		6	10/01/85
J-49-0, Sh 14	Reactor Core Isolation Cooling System		3	06/16/83
J-49-0, Sh 15	Reactor Core Isolation Cooling System		3	10/01/85
J-49-0, Sh 16	Reactor Core Isolation Cooling System		4	10/01/85
J-49-0, Sh 17	Reactor Core Isolation Cooling System		1	06/16/83
J-49-0, Sh 18	Reactor Core Isolation Cooling System		1	09/11/84
J-49-0, Sh 19	Reactor Core Isolation Cooling System		1	05/15/83
J-49-0, Sh 20	Reactor Core Isolation Cooling System		0	10/01/85
J-50-0, Sh 1	RCIC Pump Turbine	7.4-2	12	12/10/85
J-50-0, Sh 2	RCIC Pump Turbine		9	12/10/85
J-50-0, Sh 3	RCIC Pump Turbine		2	10/29/85
J-50-0, Sh 4	RCIC Pump Turbine		1	10/29/85
J-50-0, Sh 5	RCIC Pump Turbine		2	09/11/84
J-50-0, Sh 6	RCIC Pump Turbine		3	10/29/85
J-50-0, Sh 7	RCIC Pump Turbine		2	10/29/85
J-50-0, Sh 8	RCIC Pump Turbine		2	12/16/83
J-50-0, Sh 9	RCIC Pump Turbine		3	10/29/85
J-50-0, Sh 10	RCIC Pump Turbine		1	08/30/83
J-51-0, Sh 1	Residual Heat Removal	7.3-8	10	08/29/85
J-51-0, Sh 2	Residual Heat Removal		6	09/10/84
J-51-0, Sh 3	Residual Heat Removal		5	09/10/84
J-51-0, Sh 3A	Residual Heat Removal		0	07/12/82
J-51-0, Sh 4	Residual Heat Removal		5	09/10/84
J-51-0, Sh 4A	Residual Heat Removal		1	09/10/84
J-51-0, Sh 5	Residual Heat Removal		6	09/10/84
J-51-0, Sh 6	Residual Heat Removal		5	09/10/84
J-51-0, Sh 7	Residual Heat Removal		6	09/10/84
J-51-0, Sh 7A	Residual Heat Removal		1	12/23/83
J-51-0, Sh 8	Residual Heat Removal		6	09/10/84
J-51-0, Sh 8A	Residual Heat Removal		0	07/12/82
J-51-0, Sh 9	Residual Heat Removal		5	09/10/84
J-51-0, Sh 9A	Residual Heat Removal		2	09/10/84
J-51-0, Sh 10	Residual Heat Removal		5	09/10/84
J-51-0, Sh 10A	Residual Heat Removal		2	09/10/84
J-51-0, Sh 11	Residual Heat Removal		5	09/10/84
J-51-0, Sh 11A	Residual Heat Removal		2	09/10/84
J-51-0, Sh 12	Residual Heat Removal		5	09/10/84

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-51-0, Sh 12A	Residual Heat Removal		1	09/10/84
J-51-0, Sh 13	Residual Heat Removal		4	09/10/84
J-51-0, Sh 14	Residual Heat Removal		4	09/10/84
J-51-0, Sh 15	Residual Heat Removal		5	09/10/84
J-51-0, Sh 16	Residual Heat Removal		5	08/29/83
J-51-0, Sh 17	Residual Heat Removal		5	08/29/83
J-51-0, Sh 18	Residual Heat Removal		6	12/22/83
J-51-0, Sh 19	Residual Heat Removal		5	08/29/83
J-51-0, Sh 20	Residual Heat Removal		2	07/12/82
J-51-0, Sh 21	Residual Heat Removal		5	09/10/84
J-51-0, Sh 22	Residual Heat Removal		2	07/12/82
J-51-0, Sh 23	Residual Heat Removal		3	12/22/83
J-51-0, Sh 24	Residual Heat Removal		3	12/22/83
J-51-0, Sh 25	Residual Heat Removal		2	09/10/84
J-51-0, Sh 25A	Residual Heat Removal		1	12/22/83
J-51-0, Sh 26	Residual Heat Removal		1	12/22/83
J-51-0, Sh 27	Residual Heat Removal		2	12/22/83
J-51-0, Sh 28	Residual Heat Removal		2	12/22/83
J-51-0, Sh 29	Residual Heat Removal		2	12/22/83
J-52-0, Sh 1	Core Spray System	7.3-6	11	08/29/85
J-52-0, Sh 2	Core Spray System		4	05/02/83
J-52-0, Sh 3	Core Spray System		5	08/24/84
J-52-0, Sh 4	Core Spray System		5	08/24/84
J-52-0, Sh 5	Core Spray System		4	08/24/84
J-52-0, Sh 6	Core Spray System		3	05/02/83
J-52-0, Sh 7	Core Spray System		6	05/06/85
J-52-0, Sh 8	Core Spray System		5	12/12/83
J-52-0, Sh 9	Core Spray System		4	05/06/85
J-52-0, Sh 10	Core Spray System		4	08/24/84
J-52-0, Sh 11	Core Spray System		3	12/12/83
J-52-0, Sh 12	Core Spray System		4	08/24/84
J-53-0, Sh 1	Fuel Pool Cooling and Torus Water Cleanup		9	10/29/85
J-53-0, Sh 2	Fuel Pool Cooling and Torus Water Cleanup		8	10/29/85
J-53-0, Sh 3	Fuel Pool Cooling and Torus Water Cleanup		5	04/18/83
J-53-0, Sh 4	Fuel Pool Cooling and Torus Water Cleanup		7	10/06/84
J-53-0, Sh 5	Fuel Pool Cooling and Torus Water Cleanup		6	10/29/85
J-53-0, Sh 6	Fuel Pool Cooling and Torus Water Cleanup		5	10/06/84
J-53-0, Sh 7	Fuel Pool Cooling and Torus Water Cleanup		4	10/06/84
J-53-0, Sh 8	Fuel Pool Cooling and Torus Water Cleanup		6	10/06/84
J-53-0, Sh 9	Fuel Pool Cooling and Torus Water Cleanup		5	10/06/84
J-53-0, Sh 10	Fuel Pool Cooling and Torus Water Cleanup		7	10/29/85
J-53-0, Sh 11	Fuel Pool Cooling and Torus Water Cleanup		4	12/05/83
J-53-0, Sh 12	Fuel Pool Cooling and Torus Water Cleanup		3	10/29/85

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-55-0, Sh 1	High Pressure Coolant Injection	7.3-2	12	12/10/85
J-55-0, Sh 2	High Pressure Coolant Injection		6	08/30/84
J-55-0, Sh 3	High Pressure Coolant Injection		6	08/30/84
J-55-0, Sh 4	High Pressure Coolant Injection		7	12/10/85
J-55-0, Sh 4A	High Pressure Coolant Injection		1	12/10/85
J-55-0, Sh 5	High Pressure Coolant Injection		6	12/10/85
J-55-0, Sh 6	High Pressure Coolant Injection		6	06/25/85
J-55-0, Sh 7	High Pressure Coolant Injection		7	12/10/85
J-55-0, Sh 8	High Pressure Coolant Injection		6	06/25/85
J-55-0, Sh 9	High Pressure Coolant Injection		3	06/17/82
J-55-0, Sh 10	High Pressure Coolant Injection		3	06/17/82
J-55-0, Sh 11	High Pressure Coolant Injection		5	12/10/83
J-55-0, Sh 12	High Pressure Coolant Injection		6	12/10/85
J-55-0, Sh 13	High Pressure Coolant Injection		2	06/17/82
J-55-0, Sh 14	High Pressure Coolant Injection		3	06/25/85
J-55-0, Sh 15	High Pressure Coolant Injection		2	08/30/84
J-56-0, Sh 1	HPCI Pump Turbine		11	02/11/85
J-56-0, Sh 2	HPCI Pump Turbine		7	10/12/84
J-56-0, Sh 3	HPCI Pump Turbine		7	02/11/85
J-56-0, Sh 4	HPCI Pump Turbine		2	10/12/84
J-56-0, Sh 5	HPCI Pump Turbine		2	02/11/85
J-56-0, Sh 6	HPCI Pump Turbine		1	12/05/83
J-56-0, Sh 7	HPCI Pump Turbine		1	10/12/84
J-56-0, Sh 8	HPCI Pump Turbine		2	12/05/83
J-56-0, Sh 9	HPCI Pump Turbine		3	10/12/84
J-56-0, Sh 10	HPCI Pump Turbine		2	02/11/85
J-57-0, Sh 1	Containment Atmosphere Control	7.3-14	10	11/22/85
J-57-0, Sh 2	Containment Atmosphere Control		7	04/11/83
J-57-0, Sh 3	Containment Atmosphere Control		7	03/25/85
J-57-0, Sh 4	Containment Atmosphere Control		6	06/17/82
J-57-0, Sh 5	Containment Atmosphere Control		8	11/22/85
J-57-0, Sh 6	Containment Atmosphere Control		6	11/22/85
J-57-0, Sh 7	Containment Atmosphere Control		8	11/22/85
J-57-0, Sh 8	Containment Atmosphere Control		7	04/11/83
J-57-0, Sh 9	Containment Atmosphere Control		4	06/17/82
J-57-0, Sh 10	Containment Atmosphere Control		6	08/25/83
J-57-0, Sh 11	Containment Atmosphere Control		5	08/23/83
J-57-0, Sh 12	Containment Atmosphere Control		4	11/22/85
J-57-0, Sh 13	Containment Atmosphere Control		5	04/11/83
J-57-0, Sh 14	Containment Atmosphere Control		4	06/17/82
J-57-0, Sh 15	Containment Atmosphere Control		5	04/11/83
J-57-0, Sh 16	Containment Atmosphere Control		2	06/17/82
J-57-0, Sh 17	Containment Atmosphere Control		2	06/17/82

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-57-0, Sh 18	Containment Atmosphere Control		3	11/22/85
J-57-0, Sh 19	Containment Atmosphere Control		1	04/11/83
J-57-0, Sh 20	Containment Atmosphere Control		1	04/11/83
J-58-0, Sh 1	Containment Hydrogen Recombination System	7.3-15	8	03/25/85
J-58-0, Sh 2	Containment Hydrogen Recombination System		7	03/25/85
J-58-0, Sh 3	Containment Hydrogen Recombination System		6	08/23/83
J-58-0, Sh 4	Containment Hydrogen Recombination System		1	04/18/83
J-59-0, Sh 1	Primary Containment Instrument Gas	7.3-22	10	11/08/85
J-59-0, Sh 2	Primary Containment Instrument Gas		7	03/25/85
J-59-0, Sh 3	Primary Containment Instrument Gas		5	04/18/83
J-59-0, Sh 4	Primary Containment Instrument Gas		4	04/18/83
J-59-0, Sh 5	Primary Containment Instrument Gas		7	12/05/83
J-59-0, Sh 6	Primary Containment Instrument Gas		9	11/08/85
J-59-0, Sh 7	Primary Containment Instrument Gas		6	03/25/85
J-59-0, Sh 8	Primary Containment Instrument Gas		6	08/25/83
J-59-0, Sh 9	Primary Containment Instrument Gas		2	03/25/85
J-59-0, Sh 10	Primary Containment Instrument Gas		1	04/18/83
J-60-1	Primary Containment Leakage Rate Testing		1	12/05/83
J-61-0, Sh 1	Liquid Radwaste Collection		9	12/27/84
J-61-0, Sh 2	Liquid Radwaste Collection		6	12/27/84
J-61-0, Sh 3	Liquid Radwaste Collection		8	12/27/84
J-61-0, Sh 4	Liquid Radwaste Collection		6	01/26/84
J-61-0, Sh 5	Liquid Radwaste Collection		2	01/25/84
J-61-0, Sh 6	Liquid Radwaste Collection		2	12/27/84
J-66-0, Sh 1	Solid Radwaste Collection		7	11/14/84
J-66-0, Sh 2	Solid Radwaste Collection		1	04/26/83
J-69-0, Sh 1	Gaseous Radwaste-Recombination		9	10/29/85
J-69-0, Sh 2	Gaseous Radwaste-Recombination		4	02/17/83
J-69-0, Sh 3	Gaseous Radwaste-Recombination		7	10/29/85
J-69-0, Sh 4	Gaseous Radwaste-Recombination		3	07/23/82
J-69-0, Sh 5	Gaseous Radwaste-Recombination		4	07/23/82
J-69-0, Sh 6	Gaseous Radwaste-Recombination		6	12/03/84
J-69-0, Sh 7	Gaseous Radwaste-Recombination		4	02/17/83
J-69-0, Sh 8	Gaseous Radwaste-Recombination		4	02/17/83
J-69-0, Sh 9	Gaseous Radwaste-Recombination		6	12/03/84
J-72-0, Sh 1	Main Steam Isolation Valve Sealing System	7.3-17	7	10/29/85
J-72-0, Sh 2	Main Steam Isolation Valve Sealing System		5	10/29/85
J-72-0, Sh 3	Main Steam Isolation Valve Sealing System		4	02/28/85
J-72-0, Sh 4	Main Steam Isolation Valve Sealing System		2	01/30/81
J-72-0, Sh 5	Main Steam Isolation Valve Sealing System		5	10/29/85
J-72-0, Sh 6	Main Steam Isolation Valve Sealing System		2	01/30/81
J-72-0, Sh 7	Main Steam Isolation Valve Sealing System		2	01/30/81
J-72-0, Sh 8	Main Steam Isolation Valve Sealing System		3	04/18/83

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	LOGIC DIAGRAMS			
J-72-0, Sh 9	Main Steam Isolation Valve Sealing System		3	04/18/83
J-72-0, Sh 10	Main Steam Isolation Valve Sealing System		5	12/10/83
J-72-0, Sh 11	Main Steam Isolation Valve Sealing System		4	08/23/83
J-72-0, Sh 12	Main Steam Isolation Valve Sealing System		4	12/10/83
J-72-0, Sh 13	Main Steam Isolation Valve Sealing System		2	12/10/83
H-73-0	Administration Facility		2	07/26/83
H-74-0	Administration Facility		2	07/26/83
H-82-0	Turbine Building Supply & Exhaust		12	10/29/85
H-83-0	Reactor Building Supply	7.3-18	14	10/29/85
H-84-0	Reactor Building Exhaust & FRVS Vent	7.3-19	11	09/20/85
H-86-0	Drywell-Control		10	07/17/85
H-87-0	Chilled Water System		9	07/31/85
H-88-0	Auxiliary Building - Diesel Area	7.3-24	13	10/23/85
H-89-0	Auxiliary Building - Control Area	7.3-16	14	10/22/85
H-90-0	Auxiliary Building Control Area Chilled Water System	7.3-23	11	09/20/85
H-92-0	Auxiliary Building - Radwaste Area		11	09/09/85
H-93-0	Auxiliary Building Service Area		11	08/13/85
H-95-0	Miscellaneous Structures and Yard Building	7.3-25	9	10/22/85
H-96-0	Plant Heating		3	12/27/82
J-98-0, Sh 1	Domestic Water System		0	06/07/82
J-98-0, Sh 2	Domestic Water System		0	06/07/82
J-98-0, Sh 3	Domestic Water System		0	06/07/82
J-100-0	Turbine Miscellaneous Auxiliaries		8	08/27/85
J-101-0	Out of Service Status Display		6	09/27/85
J-102-0	High Radiation and LOCA/Isolation Signals Fanout	7.3-26	6	10/30/85
J-103-0, Sh 1	Remote Shutdown Panel Takeover Fanout		7	11/08/85
J-103-0, Sh 2	Remote Shutdown Panel Takeover Fanout		5	11/08/85
J-103-0, Sh 3	Remote Shutdown Panel Takeover Fanout		6	11/08/85
J-103-0, Sh 5	Remote Shutdown Panel Takeover Fanout		5	11/08/85
J-103-0, Sh 6	Remote Shutdown Panel Takeover Fanout		2	11/08/85
J-103-0, Sh 8	Remote Shutdown Panel Takeover Fanout		2	11/08/85
J-104-0	Excess Flow Check Valves		5	11/22/85
J-105-0	Sequencer Fanout	7.3-27	6	08/28/85
J-106-0	Bus Power Fail Fanout		5	07/13/83
J-107-0	Emergency Load Sequencer	7.3-28	3	11/14/84
J-108-0	Miscellaneous Alarm Systems		4	09/30/85
J-109-0	Redundant Reactivity Control System		2	09/28/84
	INSTRUMENTATION LOCATION DRAWINGS			
J-J0001-0	Instrument Location Drawing, Typical Legend and General Notes		4	03/24/83
J-J0101-1	Unit 1, Turbine Building Instrument (TBI) Location Plan, el 54'-0" Area 1		4	06/23/83
J-J0102-1	Unit 1, TBI Location Plan, El 77'-0" Area 1		2	11/04/82

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	INSTRUMENTATION LOCATION DRAWINGS			
J-J0103-1	Unit 1, TBI Location Plan, El 102' & 120'-0" Area 1		3	10/17/83
J-J0201-1	Unit 1, TBI Location Plan, El 54'-0" Area 2		2	10/08/82
J-J0202-1	Unit 1, TBI Location Plan, El 77'-0" Area 2		3	11/11/82
J-J0203-1	Unit 1, TBI Location Plan, El 102'-0" Area 1		2	07/02/82
J-J0205-1	Unit 1, TBI Location Plan, El 137'-0" Area 2		1	05/07/82
J-J0301-1	Unit 1, TBI Location Plan, El 54'-0" Area 3		3	10/08/82
J-J0302-1	Unit 1, TBI Location Plan, El 77'-0" Area 3		2	11/11/82
J-J0303-1	Unit 1, TBI Location Plan, El 102' & 120'-0" Area 3		4	06/21/83
J-J0305-1	Unit 1, TBI Location Plan, El 137'-0" Area 3		3	12/26/84
J-J0401-1	Unit 1, TBI Location Plan, El 54'-0" Area 4		5	06/24/85
J-J0402-1	Unit 1, TBI Location Plan, El 77'-0" Area 4		3	11/11/82
J-J0403-1	Unit 1, TBI Location Plan, El 102'-0" Area 4		4	07/29/85
J-J0404-1	Unit 1, TBI Location Plan, El 120'-0" Area 4		3	01/30/84
J-J0405-1	Unit 1, TBI Location Plan, El 137'-0" Area 4		0	01/18/82
J-J0501-1	Unit 1, TBI Location Plan, El 54"-0" Area 5		2	10/18/82
J-J0502-1	Unit 1, TBI Location Plan, El 77"-0" Area 5		2	11/04/82
J-J0503-1	Unit 1, TBI Location Plan, El 102' & 120'-0" Area 5		4	01/26/84
J-J0601-1	Unit 1, TBI Location Plan, El 54'-0" Area 6		5	01/07/84
J-J0602-1	Unit 1, TBI Location Plan, El 77'-0" Area 6		2	11/15/82
J-J0603-1	Unit 1, TBI Location Plan, El 102'-0" Area 6		4	12/28/84
J-J0604-1	Unit 1, TBI Location Plan, El 120'-0" Area 6		1	04/08/82
J-J0605-1	Unit 1, TBI Location Plan, El 137'-0" Area 6		3	12/28/84
J-J0701-1	Unit 1, TBI Location Plan, El 54'-0" Area 7		3	05/15/83
J-J0702-1	Unit 1, TBI Location Plan, El 77'-0" Area 7		4	08/26/83
J-J0703-1	Unit 1, TBI Location Plan, El 102' & 120'-0" Area 7		3	06/27/83
J-J0704-1	Unit 1, TBI Location Plan, El 120'-0" Area 7		4	01/31/84
J-J0705-1	Unit 1, TBI Location Plan, El 137'-0" Area 7		4	11/03/83
J-J0801-1	Unit 1, TBI Location Plan, El 54'-0" Area 8		2	02/04/82
J-J0802-1	Unit 1, TBI Location Plan, El 77'-0" Area 8		5	12/28/84
J-J0803-1	Unit 1, TBI Location Plan, El 102'-0" Area 8		2	10/15/84
J-J0804-1	Unit 1, TBI Location Plan, El 120'-0" Area 7		3	01/31/84
J-J0901-1	Unit 1, TBI Location Plan, El 54'-0" Area 9		5	01/16/84
J-J0902-1	Unit 1, TBI Location Plan, El 77'-0" Area 9		4	09/28/84
J-J0903-1	Unit 1, TBI Location Plan, El 102'-0" Area 9		3	12/20/82
J-J0904-1	Unit 1, TBI Location Plan, El 120'-0" Area 9		4	12/26/84
J-J0905-1	Unit 1, TBI Location Plan, El 171'-0" Area 9		1	09/28/82
J-J0906-1	Unit 1, TBI Location Plan, El 171'-0" Area 9		3	01/26/84
J-J1001-1	Unit 1, TBI Location Plan, El 54'-0" Area 10		5	07/12/83
J-J1002-1	Unit 1, TBI Location Plan, El 77'-0" Area 10		4	06/27/83
J-J1003-1	Unit 1, TBI Location Plan, El 102'-0" Area 10		3	12/20/82
J-J1004	Unit 1, TBI Location Plan, El 120'-0" Area 10		2	10/06/84
J-J1005-1	Unit 1, TBI Location Plan, El 137'-0" Area 10		3	02/21/84
J-J1006-1	Unit 1, TBI Location Plan, El 171'-0" Area 10		1	09/13/82

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	INSTRUMENTATION LOCATION DRAWINGS			
J-J1101-1	Unit 1, TBI Location Plan, El 54'-0" Area 11		4	08/12/83
J-J1102-1	Unit 1, TBI Location Plan, El 77'-0" Area 11		5	08/12/83
J-J1103-1	Unit 1, TBI Location Plan, El 102'-0" Area 11		3	06/21/83
J-J1104-1	Unit 1, TBI Location Plan, El 120'-0" Area 11		1	07/26/82
J-J1105-1	Unit 1, TBI Location Plan, El 137'-0" Area 11		3	12/17/84
J-J1106-1	Unit 1, TBI Location Plan, El 171'-0" Area 11		3	10/17/83
J-J1201-1	Unit 1, TBI Location Plan, El 54'-0" Area 12		5	12/26/84
J-J1202-1	Unit 1, TBI Location Plan, El 77'-0" Area 12		4	12/26/84
J-J1203-1	Unit 1, TBI Location Plan, El 102'-0" Area 12		3	09/21/84
J-J1205-1	Unit 1, TBI Location Plan, El 137'-0" Area 12		2	10/17/83
J-J1206-1	Unit 1, TBI Location Plan, El 171'-0" Area 12		1	09/01/82
J-J4101-0	Unit 1, TBI Location Plan, El 54'-0" Area 41		4	10/24/83
J-J4102-0	Unit 1, TBI Location Plan, El 77'-0" Area 41		1	11/16/82
J-J4103-2	Unit 1, TBI Location Plan, El 102'0" Area 41		0	11/20/81
J-J4501-0	Unit 1, TBI Location Plan, El 54'-0" Area 45		3	11/15/82
J-J4502-0	Unit 1, TBI Location Plan, El 77'-0" Area 45		2	10/17/83
J-J4901-0	Unit 1, TBI Location Plan, El 54'-0" Area 49		3	04/03/84
J-J4902-0	Unit 1, TBI Location Plan, El 77'-0" Area 49		3	01/12/84
J-J1301-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 13		8	04/08/85
J-J1302-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 13		5	11/10/83
J-J1303-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area AT		3	11/11/82
J-J1304-1	Unit 1, Reactor Building Instrument Location Plan, El 132'&145"-0" A'	Area 13 PL	4	09/23/83
J-J1401-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 14		4	05/22/85
J-J1402-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 14		4	07/16/83
J-J1403-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 16		7	01/22/85
J-J1404-1	Unit 1, Reactor Building Instrument Location Plan, El 132'-0" Area 14 PL		4	11/08/83
J-J1405-1	Unit 1, Reactor Building Instrument Location Plan, El 145'-0" Area 14 PL		1	07/20/83
J-J1406-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-0" Area 14 PL		1	03/08/83
J-J1501-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 15		7	04/08/85
J-J1502-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 15		3	09/14/82
J-J1503-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0 Area 15		3	12/10/83
J-J1504-1	Unit 1, Reactor Building Instrument Location Plan, El 132'&145'-0" Area 15		4	09/23/83
J-J1601-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 16		5	05/22/85
J-J1602-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 16		7	09/21/84
J-J1603-1	Unit 1, Reactor Building Instrument Location Plan, El 100'-2" Area 17		4	02/28/85
J-J1604-1	Unit 1, Reactor Building Instrument Location Plan, El 132'-0" Area 16		3	07/12/83
J-J1605-1	Unit 1, Reactor Building Instrument Location Plan, El 145'-0" Area 16		4	05/10/85
J-J1606-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-0" Area 16		3	06/15/83
J-J1702-1, Sh 1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 17		5	05/06/85
J-J1702-1, Sh 2	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 17		3	09/11/85
J-J1702-1, Sh 3	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 17		0	10/12/82
J-J1703-1	Unit 1, Reactor Building Instrument Location Plan, El 100'-2" Area 17		5	03/25/85

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	INSTRUMENTATION LOCATION DRAWINGS			
J-J1705-1	Unit 1, Reactor Building Instrument Location Plan, El 121'-71 1/2" Area 17		2	07/21/83
J-J1706-1	Unit 1, Reactor Building Instrument Location Plan, El 132'-0" Area 17		2	07/27/83
J-J1707-1	Unit 1, Reactor Building Instrument Location Plan, El 145'-0" Area 17		1	06/23/83
J-J1708-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-0" Area 17		4	04/08/85
J-J1801-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 18		5	01/22/85
J-J1802-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 18		3	01/30/84
J-J1803-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 18		5	09/11/85
J-J1804-1	Unit 1, Reactor Building Instrument Location Plan, El 132'-0" Area 18		2	11/16/82
J-J1806-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-0" Area 18		4	10/24/84
J-J1901-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 19		7	05/20/85
J-J1902-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 19		4	11/25/85
J-J1903-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 19		6	05/21/85
J-J1904-1	Unit 1, Reactor Building Instrument Location Plan, El 132'&145'-0" Area 19		1	10/14/83
J-J1905-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-201'-0" Area 19		3	08/07/85
J-J2001-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 20		4	05/22/85
J-J2002-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 20		5	11/08/83
J-J2003-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 20		2	10/26/82
J-J2006-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-0" Area 20		5	09/27/85
J-J2007-1	Unit 1, Reactor Building Instrument Location Plan, El 201'-0" Area 20		2	11/08/83
J-J2101-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 21		7	09/23/83
J-J2102-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 21		4	05/16/83
J-J2103-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 21		3	06/15/83
J-J2105-1	Unit 1, Reactor Building Instrument Location Plan, El 162'-201'-0" Area 21		5	12/26/84
J-J2201-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 22		8	11/10/83
J-J2202-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 22		4	02/15/84
J-J2203-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 22		4	06/03/83
J-J2301-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 23		6	07/29/85
J-J2302-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 23		6	09/27/85
J-J2303-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 23		4	11/08/83
J-J2401-1	Unit 1, Reactor Building Instrument Location Plan, El 54'-0" Area 24		7	10/24/83
J-J2402-1	Unit 1, Reactor Building Instrument Location Plan, El 77'-0" Area 24		3	12/27/83
J-J2403-1	Unit 1, Reactor Building Instrument Location Plan, El 102'-0" Area 24		5	11/10/83
J-J2501-1	Unit 1, Auxiliary Building El 54'-0" Area 25		1	06/18/82
J-J2502-1	Unit 1, Auxiliary Building El 77'-0" Area 24		1	06/18/82
J-J2506-1	Unit 1, Auxiliary Building El 155'-0" Area 25		4	04/20/84
J-J2601-1	Unit 1, Auxiliary Building El 54'-0" Area 25		2	10/25/82
J-J2606-1	Unit 1, Auxiliary Building El 155'-0" Area 26		5	09/27/85
J-J2701-1	Unit 1, Auxiliary Building El 54'-0" Area 27		8	10/15/84
J-J2702-1	Unit 1, Auxiliary Building El 77'-0" Area 27		3	02/07/84
J-J2703-1	Unit 1, Auxiliary Building El 102'-0" Area 27		5	09/21/84
J-J2704-1	Unit 1, Auxiliary Building El 130'-0" Area 27		4	07/17/84
J-J2801-1	Unit 1, Auxiliary Building El 54'-0" Area 28		6	10/15/84
J-J2802-1	Unit 1, Auxiliary Building El 77'-0" Area 28		3	02/07/84

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	INSTRUMENTATION LOCATION DRAWINGS			
J-J2803-1	Unit 1, Auxiliary Building El 102'-0" Area 28		5	09/21/84
J-J2804-1	Unit 1, Auxiliary Building El 130'-0" Area 28		2	08/26/83
J-J3101-0, Sh 1	Unit 1, Auxiliary Building El 54'-0" Area 31		6	09/25/84
J-J3101-0, Sh 2	Unit 1, Auxiliary Building El 75'-0" Area 31		4	04/18/83
J-J3201-0, Sh 1	Unit 1, Auxiliary Building El 54'-0" Area 32		6	02/28/83
J-J3201-0, Sh 2	Unit 1, Auxiliary Building El 75'-0" Area 32		3	04/18/83
J-J3202-0	Unit 1, Auxiliary Building El 87'-0" Area 32		3	09/23/83
J-J3203-0, Sh 1	Unit 1, Auxiliary Building El 102'-0" Area 32		1	09/09/81
J-J3206-0	Unit 1, Auxiliary Building El 153'-0" Area 32		2	06/15/83
J-J3301-0	Unit 1, Auxiliary Building El 54'-0" Area 33		5	11/22/83
J-J3401-0, Sh 1	Unit 1, Auxiliary Building El 54'-0" Area 34		6	07/13/83
J-J3401-0, Sh 2	Unit 1, Auxiliary Building El 54'-0" Area 34		-	---
J-J3403-0	Unit 1, Auxiliary Building El 102'-0" Area 34		5	02/13/84
J-J3501-0	Unit 1, Auxiliary Building El 54'-0" Area 35		11	03/01/85
J-J3502-0	Unit 1, Auxiliary Building El 87'-0" Area 35		3	04/18/83
J-J3503-0	Unit 1, Auxiliary Building El 102'-0" Area 35		6	07/15/85
J-J3506-0	Unit 1, Auxiliary Building El 135'-3" Area 35		6	10/15/84
J-J7101-0	Unit 1, Auxiliary Building El 54'-0" Area 71		5	6/10/85
J-J7201-0	Unit 1, Auxiliary Building El 54'-0" Area 72		2	07/19/82
J-J7206-0	Unit 1, Auxiliary Building El 153'-0" Area 72		2	03/23/83
J-J7301-0	Unit 1, Auxiliary Building El 54'-0" Area 73		6	06/15/83
	ELEMENTARY DIAGRAMS			
C-163C1723	Motor-Operated Valve & Motor Control Center Standards		4	12/18/78
C-762E180	Reactor Recirculation Pump & Motor Generator Set		BR0	07/12/83
C-791E401AC	Nuclear Steam Supply Shutoff System		BR1	12/06/83
C-791E402AC	Nuclear Boiler Process Instrumentation System		BR0	12/06/83
C-791E403AC	Auto Depressurization System		BR0	12/06/83
C-791E406AC	Reactor Manual Control System		BR1	12/05/83
C-791E407AC	Control Rod Drive Hydraulic System		BR0	01/04/84
C-791E408AC	Feedwater Control System		BR1	12/05/83
C-791E409AC	Standby Liquid Control System		6	12/16/83
C-791E410AC	Startup Range Neutron Monitoring System		BR1	05/24/84
C-791E411AC	Power Range Neutron Monitoring System		BR1	12/05/83
C-791E412AC	Startup Range Detector Drive Control		2	02/16/82
C-791E413AC	Transverse Incore Probe Calibration System		BR1	05/24/84
C-791E414AC	Reactor Protection System		BR1	12/02/83
C-791E415AC	Interconnection Schematic		2	11/11/82
C-791E418AC	Residual Heat Removal System		BR0	12/05/83
C-791E419AC	Core Spray System		BR1	12/09/83
C-791E420AC	High Pressure Coolant Injection System		BR1	12/09/83
C-791E421AC	Reactor Core Isolation Cooling System		BR1	12/09/83

TABLE 1.7-3 (Cont)

Drawing Number	Title	FSAR Figure Number	Rev	Date
	ELEMENTARY DIAGRAMS			
C-791E425AC	Steam Leak Detection System		BR1	01/04/84
C-807E168AC	Process Radiation Monitoring System		BR1	01/12/84
C-865E346AC	Jet Pump Instrumentation System		BR2	01/12/84
C-865E366	Reactor Water Cleanup System		BR1	05/09/84
C-866E142	Radwaste System		BR0	12/09/83
115D6002AC	RPS MG Set Control		BR0	10/20/83
	FUNCTIONAL CONTROL DIAGRAMS			
C-729E608AC	Reactor Water Cleanup System		1	11/21/83
C-729E613AC	Core Spray System		GC	04/15/82
C-729E618AD	Control Rod Drive Hydraulic System		3	11/18/83
C-729E622AC	Reactor Core Isolation Cooling System		1	02/15/84
C-729E625	Reactor Recirculation System		6	12/21/82
C-729E627AC	High Pressure Coolant Injection System		2	03/29/83
C-729E630AC	Residual Heat Removal System		BC	06/23/83
C-729E631AC	Neutron Monitoring System		1	03/23/84
C-919D694AC	Standby Liquid Control System		1	12/21/82

1.8 CONFORMANCE TO NRC REGULATORY GUIDES

1.8.1 Non-NSSS Assessment of Conformance

The extent of Non-Nuclear Steam Supply System (NSSS) compliance with the NRC Regulatory Guides is indicated here and, where applicable, reference is made to the Final Safety Analysis Report (FSAR) section(s) that describe the appropriate design feature.

Determination of conformance is based on a comparison of the Hope Creek Generating Station (HCGS) non-NSSS design and construction to the latest version of the Regulatory Guides. Variances are discussed and justified in this section where the design deviates from regulatory guidelines, or where compliance has been qualified by an interpretation of the Regulatory Guide. Positions stated with respect to Regulatory Guide compliance will apply during the operations phase unless otherwise stated. In general, the statement, "although Regulatory Guide 1.XXX does not apply to HCGS, per its implementation section..." applies only during construction and startup phase; i.e., the Regulatory Guide is applicable during the operations phase.

1.8.1.1 Conformance to Regulatory Guide 1.1 (Safety Guide 1) Revision 0, November 2, 1970: Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps

HCGS complies with Regulatory Guide 1.1, as described below.

The suction piping for all pumps required for safe shutdown of the reactor, during both normal and accident conditions, including the cooling of both the core and the containment, is designed and located to ensure adequate net positive suction head (NPSH). The available NPSH for the residual heat removal (RHR) and core spray pumps is based on a torus water temperature of 212°F, with the pool surface at 14.7 psia. The calculated available NPSH for the high pressure coolant injection (HPCI) pump is based on a water temperature of 170°F, with the pool surface at 14.7 psia.

For further discussion, see Sections 5.4.7, 6.2.2, and 6.3.2.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.2 Conformance to Regulatory Guide 1.2, (Safety Guide 2) Revision 0, November 2, 1970: Thermal Shock to Reactor Pressure Vessels

Although NRC Regulatory Guide 1.2 was withdrawn by the NRC on July 31, 1991, HCGS commitments, as stated below, are not affected by this withdrawal.

HCGS complies with Regulatory Guide 1.2, as described below:

An investigation of the structural integrity of boiling water reactor (BWR) pressure vessels during a design basis accident (DBA) determined that, based on the methods of fracture mechanics, failure of the vessel by brittle fracture does not occur as a result of a DBA.

See Section 5.3 for further discussion of fracture toughness of the reactor pressure vessel (RPV) and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.3 Conformance to Regulatory Guide 1.3, Revision 2, June 1974: Assumptions Used For Evaluating The Potential Radiological Consequences of a Loss of Coolant Accident For Boiling Water Reactors

HCGS complies with Regulatory Guide 1.183 instead.

1.8.1.4 Conformance to Regulatory Guide 1.4, Revision 2, June 1974: Assumptions Used For Evaluating The Potential Radiological Consequences of a Loss of Coolant Accident For Pressurized Water Reactors

Regulatory Guide 1.4 deals with pressurized water reactors (PWRs) only and is, therefore, not applicable to HCGS.

1.8.1.5 Conformance to Regulatory Guide 1.5 (Safety Guide 5), Revision 0, February 1, 1971: Assumptions Used for Evaluating The Potential Radiological Consequences of Steam Line Break Accident For Boiling Water Reactors

HCGS complies with Regulatory Guide 1.5. See Chapter 15 for discussion of accident analyses.

1.8.1.6 Conformance to Regulatory Guide 1.6 (Safety Guide 6), Revision 0, March 10, 1971: Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

HCGS complies with Regulatory Guide 1.6, as described below.

The ac and dc safety-related equipment and control power loads are separated into redundant load groups, each of which is connected to independent standby power sources. No provisions are made for paralleling standby power sources or for connecting redundant load groups together.

For further discussion of the Onsite Electrical System, see Sections 7.1.2, 7.2.1, 8.3.1, and 8.3.2.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.7 Conformance to Regulatory Guide 1.7, Revision 2, November 1978: Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident

HCGS complies with Regulatory Guide 1.7, except as noted below. Position C.1 of Regulatory Guide 1.7 specifies that HCGS "should have the capability to ... mix the atmosphere in the containment." The drywell fans have not been classified as safety-related to provide post-accident mixing. Analyses indicate that adequate mixing is obtained from convection, diffusion, and turbulence and that no mechanical means of mixing is necessary.

The Nuclear Regulatory Commission (NRC or the Commission) has revised Title 10 of the Code Of Federal Regulations (10 CFR) Section 50.44, "Standards For Combustible Gas Control System In Light-Water Power Reactors." The amended standards eliminated the requirements for hydrogen recombiners and relaxed the requirements for hydrogen and oxygen monitoring. On August 9, 2005, the NRC issued Amendment 160 to the Hope Creek Facility Operating License to allow the plant to implement the revised rule. Amendment 160 constitutes the current licensing commitment, in lieu of the guidance specified in Regulatory Guide 1.7, with regard to the requirements for the hydrogen recombiners and for hydrogen and oxygen monitoring systems.

For further discussion of the design of combustible gas control in containment, see Section 6.2.5.

1.8.1.8 Conformance to Regulatory Guide 1.8, Revision 2, April 1987: Qualification and Training of Personnel for Nuclear Power Plants

HCGS complies with Regulatory Guide 1.8, except as noted below. The Operations Manager shall either hold an SRO license or have held an SRO license for a similar unit (BWR) or have been certified at an appropriate simulator for equipment senior operator knowledge. Licensed Operator qualifications and training shall be in accordance with 10CFR55. The Radiation Protection Manager shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The Director – Nuclear Oversight (NOS) and the engineering manager positions under the Site Engineering Director, which correspond to the Engineer in Charge, must meet or exceed the qualifications of ANSI/ANS 3.1-1981. Qualification requirements for the Nuclear Safety Review Board personnel performing the offsite independent review function and PORC members are described in their associated program documents.

See Section 12.5 and Section 13 for further discussion of staffing of plant personnel.

1.8.1.9 Conformance to Regulatory Guide 1.9, Revision 2, December 1979: Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants

Although Regulatory Guide 1.9 is not applicable to HCGS, per its implementation section, HCGS complies with IEEE 387-1977, as endorsed and modified by Regulatory Guide 1.9, subject to the clarifications stated below:

Paragraph C.4 requires that the frequency and voltage not decrease to less than 95 percent of nominal and 75 percent of nominal, respectively, at any time during the loading sequence. At HCGS, because the two unit substation transformers remain connected to the diesel generator bus all the time, the voltage will dip below 75% of rated voltage upon the closure of the generator breaker for a DBA or loss of offsite power (LOP). This voltage dip is due to the excitation current inrush while the transformers are energized and lasts for approximately six cycles. The first motor load applied is the RHR motor, after closure of the SDG circuit breaker. The RHR circuit breaker has a closing permissive from the bus undervoltage relays. With the current setting of these relays (set to dropout at 70 percent and to pickup at 78 percent) the RHR motor circuit breaker will close when permitted. It takes 4.5 cycles for this circuit breaker to close. During this interval the generator has recovered its voltage in excess of 90 percent. This will be verified during the preoperational tests described in Section 14.2.12.1.30.

Compliance with Position C.6 of Regulatory Guide 1.9 is discussed in Section 1.8.1.108.

The order of testing specified in Regulatory Position C.14 is not applicable to Hope Creek. The Hope Creek order of testing is as described in the Hope Creek Technical Specifications.

For further discussion of onsite power systems, see Section 8.3.

1.8.1.10 Conformance to Regulatory Guide 1.10, Revision 1, January 2, 1973: Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures

Although Regulatory Guide 1.10 was withdrawn by the NRC on July 21, 1981, HCGS complies with it.

The original Cadweld testing program in the Preliminary Safety Analysis Report (PSAR) was based on using only sister splices. The program was later revised before the start of construction to conform with the Regulatory Guide using a combination of production and sister splices. When newer technical criteria for Cadwelding developed, the architect/engineer revised the program to delete the tensile test frequency requirements for each splicing crew. The new criteria conformed to the requirements of ANSI N45.2.5, 1978, as endorsed by Regulatory Guide 1.94. However, the letter dated August 5, 1981, NRC to PSE&G, from R. L. Tedesco to R. L. Mittl, requested that the sample frequency requirements of this guide be implemented. Since November 30, 1981, HCGS has been in complete compliance with this Regulatory Guide.

For further discussion, see Section 3.8.6.

1.8.1.11 Conformance to Regulatory Guide 1.11 (Safety Guide 11), Revision 0, February 1, 1971: Instrument Lines Penetrating Primary Reactor Containment

HCGS complies with Regulatory Guide 1.11, except as noted below.

Containment pressure sensing lines are not provided with an automatic or remotely operated isolation valve as specified in Position C.1.c of Regulatory Guide 1.11. Sensing lines are not isolated automatically upon a containment isolation signal because the pressure sensors provide a Reactor Protection System (RPS) signal. The capability for remote operation is not useful to the operator because remote indication of failure of a specific line is not available. However, these lines are provided with manual isolation valves for local operation and are checked for leakage during normal instrumentation calibrations.

For further discussion of containment isolation provisions, see Section 6.2.4.

1.8.1.12 Conformance to Regulatory Guide 1.12, Revision 1, April 1974: Instrumentation for Earthquakes

HCGS complies with ANSI N18.5-1974, as endorsed and modified by Regulatory Guide 1.12, subject to the clarification that the response-spectrum recorders required by Paragraph C.1.c are not supplied as discrete instruments. Instead, triaxial time history accelerographs are provided, at the required locations, with a multichannel magnetic tape recorder and a response spectrum analyzer. This system provides more complete information than that presented by response spectrum recorders.

For further discussion, see Section 3.7.4.

1.8.1.13 Conformance to Regulatory Guide 1.13, Revision 1, December 1975: Spent Fuel Storage Facility Design Basis

HCGS complies with Regulatory Guide 1.13 with the following exception:

Position C.3 of Regulatory Guide 1.13 requires that interlocks be provided to prevent cranes from passing over stored fuel when fuel handling is not in progress.

At HCGS, only the main hoist of the Reactor Building polar crane is physically restricted from travelling over the spent fuel pool. The 10-ton auxiliary hoist has no such travel restriction. Restricting its travel over the fuel pool is not part of the polar crane design basis. Instead, the alternate crane design basis of a single failure proof auxiliary hoist, described in FSAR Section 9.1.5.3.1, is used. No loads are required to be routinely handled over the fuel pool when fuel handling is not in progress. In the event a light load must be handled over stored fuel, a single failure proof handling system will be used.

See Section 9.1 for further discussion of the fuel handling and storage facilities and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.14 Conformance to Regulatory Guide 1.14, Revision 1, August 1975: Reactor Coolant Pump Flywheel Integrity

Regulatory Guide 1.14 is not applicable to HCGS. The reactor recirculation pumps at HCGS do not have inertia flywheels.

1.8.1.15 Conformance to Regulatory Guide 1.15, Revision 1, December 28, 1972: Testing of Reinforcing Bars for Category I Concrete Structures

Although Regulatory Guide 1.15 was withdrawn by the NRC on July 21, 1981, HCGS complies with it.

For further discussion, see Section 3.8.6.

1.8.1.16 Conformance to Regulatory Guide 1.16, Revision 4, August 1975: Reporting of Operating Information Appendix A Technical Specification

HCGS complies with Generic Letter 97-02, Revised Contents of the Monthly Operating Report, in lieu of the guidance provided in draft Regulatory Guide 1.16, Revision 4, as allowed by Generic Letter 97-02.

1.8.1.17 Conformance to Regulatory Guide 1.17, Revision 1, June 1973: Protection of Nuclear Power Plants Against Industrial Sabotage

Although NRC Regulatory Guide 1.17 was withdrawn by the NRC on July 5, 1991, HCGS commitments, as stated below, are not affected by this withdrawal.

HCGS complies with 10CFR73.55, Requirement for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage.

1.8.1.18 Conformance to Regulatory Guide 1.18, Revision 1, December 28, 1972: Structural Acceptance Test For Concrete Primary Reactor Containments

Regulatory Guide 1.18 was withdrawn by the NRC on July 21, 1981, and is not applicable to HCGS.

1.8.1.19 Conformance to Regulatory Guide 1.19 (Safety Guide 19), Revision 1, August 11, 1972: Nondestructive Examination of Primary Containment Linear Welds

Regulatory Guide 1.19 was withdrawn by the NRC on July 21, 1981, and is not applicable to HCGS.

1.8.1.20 Conformance to Regulatory Guide 1.20, Revision 2, May 1976: Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing

HCGS complies with Regulatory Guide 1.20, with the clarification that the HCGS reactor internals were tested in accordance with the provisions for nonprototype Seismic Category I plants. The results of the vibration assessment program are found in GE Licensing Topical Report NEDE-24057, Reference 1.8-1.

For a discussion of the preoperational flow test and inspection program, see Sections 3.9.2.6 and 14.2.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.21 Conformance to Regulatory Guide 1.21, Revision 1, June 1974: Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light Water Cooled Nuclear Power Plants

HCGS complies with Regulatory Guide 1.21, with the clarifications outlined below:

Position C.13 and Appendix B, Paragraph E, of Regulatory Guide 1.21 require that potential dose calculations to individuals and populations should be performed. Estimates of average doses to persons in the environs of the plant are based on conservative doses to individuals; actual individual exposures are expected to be substantially less.

Appendix A, Paragraph C, of Regulatory Guide 1.21 requires that the total curie quantity and radionuclide composition of solid waste shipped offsite be determined.

Curie and radionuclide determinations for solid radioactive waste shipped offsite are performed to the extent and level required by Department of Transportation Regulations and 10CFR71, Packaging of Radioactive Material. Any additional monitoring is unnecessary and will increase personnel exposures.

1.8.1.22 Conformance to Regulatory Guide 1.22 (Safety Guide 22), Revision 0, February 17, 1972: Periodic Testing of Protection System Actuation Functions

HCGS complies with Regulatory Guide 1.22 based on the interpretations listed below.

The systems classed as important to safety, as defined in IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, are:

1. Reactor Protection System (RPS), described in Section 7.2.

2. Primary Containment Isolation System (PCIS) and nuclear steam supply system shutoff (NSSSS), described in Section 7.3.

3. Reactor Core Isolation Cooling (RCIC) System described in Section 5.4.6.

4. Filtration, Recirculation, and Ventilation System (FRVS), described in Section 6.8.

5. Station Service Water System (SSWS), described in Section 9.2.1.

6. Safety Auxiliaries Cooling System (SACS), described in Section 9.2.2.

Position D.3.a of Regulatory Guide 1.22 requires that "positive means" be provided to prevent expansion of the bypass condition to redundant or diverse systems. Administrative controls are considered a "positive means" of preventing expansion of the bypass condition, since interlocks between systems could lead to common mode failures.

Position D.3.b in Regulatory Guide 1.22 is interpreted to require indication of bypass on a system basis, not necessarily by component.

For additional discussion of the design of the HCGS electrical system, see Section 7 and Section 8.1.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.23 Conformance to Regulatory Guide 1.23 (Safety Guide 23), Revision 0, February 17, 1972: Onsite Meteorological Programs

HCGS complies with the intent of Regulatory Guide 1.23.

1.8.1.24 Conformance to Regulatory Guide 1.24 (Safety Guide 24), Revision 0, March 23, 1972: Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure

Regulatory Guide 1.24 is not applicable to HCGS.

1.8.1.25 Conformance to Regulatory Guide 1.25 (Safety Guide 25), Revision 0, March 23, 1972: Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors

HCGS complies with Regulatory Guide 1.183, Appendix B, instead.

1.8.1.26 Conformance to Regulatory Guide 1.26, Revision 3, February 1976: Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants

HCGS complies with Regulatory Guide 1.26, with the clarifications outlined below.

PSE&G does recognize the need for the assurance of the specified operation of certain non-safety-related structures, systems and components, such as fire protection systems, radioactive waste treatment, handling and storage systems, and Seismic Category II/I items. Such assurance is documented through the specification of limited quality assurance programs (described in Table 3.2-1, footnotes 22, 50 and 52. In addition, items designated "R" in Table 3.2-1 will be included in the QA program during operations to the extent required by Regulatory Guide 1.143.

The exception to Position C.2.b is that since the reactor recirculation pumps do not perform any safety function and since failure of the reactor coolant pumps due to seal or cooling water failure does not have serious safety implications, the control rod drive (CRD) seal purge supply and Reactor Auxiliaries Cooling System (RACS) cooling water to the seal coolers are quality group D.

Additionally, Position C.2.b of Regulatory Guide 1.26 requires that cooling water systems important to the safety function of the standby diesel generators be Quality Group C. HCGS's diesel generator cooling water systems are classified as Quality Group C except for the engine mounted piping systems (such as the lube oil headers, water headers, cylinder heads, etc). The engine mounted piping systems are part of the diesel engine and its auxiliary support systems which, as stated in Section B of the Regulatory Guide, are not covered by this guide. These systems are manufactured to the manufacturer's proprietary design requirements which do not necessarily meet the requirements of ASME Section III or ANSI B.31. However, the components used are pressure tested and the manufacturing processes are monitored as a part of the suppliers approved QA program, which addresses the 18 criteria contained within 10 CFR 50, Appendix B.

Additional quality assurance requirements invoked by the applicant include:

1. periodic documented subsupplier audits (including plant visits),

2. review and approval of subsupplier QA programs and manuals,

3. test and inspection audits,

4. calibration of test gauges before and after use, and

5. control of calibration records and acceptance devices.

With the imposition of the above design, manufacturing, and testing controls, the on-skid and off-skid piping and components have been made to be equivalent to Quality Group C. This meets the requirements in Section B of the guide to design, fabricate, erect and test the diesel engine and its auxiliary support systems to quality standards commensurate with the safety function to be performed.

NUREG-0737, Item II.k.3.25 extends the requirements of Position C.2.b by requiring demonstration that the consequences stemming from a loss of cooling water to the reactor recirculation pump seal coolers is acceptable following a loss of power for at least 2 hours. NEDO-24951 (Reference 5.4-4) confirms that the HCGS design meets the requirements of NUREG-0737, Item II.k.3.25.

See Section 3.2.2 for further discussion and Section 1.8.2 for NSSS assessment of this Regulatory Guide.

1.8.1.27 Conformance to Regulatory Guide 1.27, Revision 2, January 1976: Ultimate Heat Sink For Nuclear Power Plants

HCGS complies with Regulatory Guide 1.27. The ultimate heat sink (UHS) is the Delaware River, which is a large, single water source as defined by the Regulatory Guide. The service water equipment required for the dissipation of residual heat is all safety-related and redundant, with the exception of the service water discharge piping outside of the Reactor Building. This piping normally discharges into the Circulation Water System (CWS). However, if some natural or site-related event occurs and blocks the flow, there are rupture discs in the safety-related portion of the service water discharge piping that allow the water to be safely diverted onto and across the lower yard surface area, thus completing the cooling loop between the UHS and the plant.

For further discussion of the Station Service Water System (SSWS) and the UHS, see Sections 9.2.1 and 9.2.5.

1.8.1.28 Conformance to Regulatory Guide 1.28, Revision 2, February 1979: Quality Assurance Program Requirements (Design and Construction)

Although Regulatory Guide 1.28, Revision 2, is not applicable to HCGS, HCGS complies with NQA-1-1994.

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1.8.1.29 Conformance to Regulatory Guide 1.29, Revision 3, September 1978: Seismic Design Classification

HCGS complies with Regulatory Guide 1.29, except as noted below.

Position C.1.b of Regulatory Guide 1.29 requires the reactor core and reactor vessel internals be designated Seismic Category I and should be designed to withstand the effects of the SSE and remain functional.

Application of this guide is limited to those reactor vessel internals that are part of engineered safety features (ESFs), such as core spray piping, core spray sparger and hardware, etc.

Position C.1.e of Regulatory Guide 1.29 requires that those portions of the steam systems of boiling water reactors extending from the outermost primary containment isolation valve up to but not including the turbine stop valve and connected piping of 2-1/2 inches or larger nominal pipe size up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation be designated as Seismic Category I and be designed to withstand the effects of a safe shutdown earthquake (SSE) and remain functional. This position also requires that the pertinent quality assurance requirements of Appendix B to 10CFR50 be applied to all activities affecting the safety-related functions of these systems and components. Additionally, the turbine stop valve should be designed to withstand the SSE and maintain its integrity.

The main steam line classification and design is based on the approach discussed in Standard Review Plan 3.2.2, Revision 1, July 1981, Appendix B. The main steam lines (MSL) from the second isolation valve up to and including MS stop valve and all the branch lines 2 1/2-inches in diameter and larger between these two valves up to and including the first valve in the branch line is classified under quality group B (ASME Section III, Class 2). The main steam line piping between MS stop and the turbine main stop valve is ASME Section III, Class 3 instead of D classification as required in

Appendix B. This portion of MSL is not classified as safety-related, is not specifically designed to Seismic Category I standards, and is not housed in Seismic Category I structures, as discussed in Appendix B. This different approach satisfies SRP 3.2.2 acceptance criteria requirements and results in an acceptable level of safety.

Position C.1.h requires that cooling water and seal water systems or portions of these systems that are required for functioning of Reactor Coolant System components important to safety, such as reactor coolant pumps, be designated and designed as Seismic Category I systems and components.

The CRD seal purge and seal cooling from the RACS for the reactor recirculation pumps are not designed to withstand an SSE, as the reactor recirculation pumps do not perform any safety function, and failure does not have serious safety implications. NUREG-0737, Item II.k.3.25 extends the requirements of Position C.1.h by requiring demonstration that the consequences stemming from a loss of cooling water to the reactor recirculation pump seal coolers is acceptable following a loss of ac power for at least 2 hours. NEDO-24951 (Reference 5.5-4) confirms that the HCGS design meets the requirements of NUREG-0737, Item II.k.3.25. NEDO-24083 (Reference 1.8-2) shows that if the seal and cooling systems to the reactor recirculation pump fail to operate, the leakage past the recirculation pump seal is sufficiently small so that no safety concerns exist.

Position C.2 of Regulatory Guide 1.29 requires that items that would otherwise be classified non-Seismic Category I, "but whose failure could reduce the functioning" of the items important to safety "to an unacceptable safety level," are to be "designed and constructed so that the SSE would not cause such failure." In addition, Position C.4 of Regulatory Guide 1.29 requires that the pertinent quality assurance requirement of Appendix B to 10CFR50 be applied to the safety requirements of such items. Both these requirements are considered to be adequately met by establishing the following practices to such items:

1. During the construction and operations phase, design and design control for features of such items that should not fail are carried out in the same manner as for items directly important to safety. This includes the performance of appropriate design reviews.

2. During the construction phase, field work is performed under the direction of experienced field construction superintendents and is inspected by quality control engineers stationed at the site. The quality control engineers are responsible for verifying that construction is performed in accordance with the design drawings and specifications and with applicable standard codes and specifications. Field Engineering inspection records may be accepted in lieu of quality control for items installed prior to initiation of this program or for specific cases, such as where disassembly would be required to perform the inspection. Each exception will require approval from Bechtel Quality Assurance.

3. During the construction phase, such items are neither purchased to a code higher than normal system design dictates, nor is the quality assurance program of 10CFR50, Appendix B, applied to their procurement. However, these items are identified in the applicable documents. During the operations phase applicable procurement documents, design modifications documents, and station work orders will be reviewed for designation of appropriate quality assurance controls.

Position C.3 of Regulatory Guide 1.29 requires that Seismic Category I design requirements be extended "to the first seismic restraint beyond the defined boundaries." Since seismic analysis of a piping system necessitates division of the systems into discrete segments terminated by fixed points, the seismic design cannot be terminated at a seismic restraint. However, it is extended to the first point in the system that can be treated as an anchor to the plant structure. In addition, Position C.4 of Regulatory Guide 1.29 requires that the pertinent quality assurance requirement of Appendix B to 10CFR50 be applied to the safety requirements of such items. Both these requirements are considered to be met adequately by establishing the following practices:

1. During the construction and operations phase, design and design control for such items are carried out in the same manner as for items directly important to safety. This includes the performance of appropriate design reviews.

2. During the construction and operations phase, walk-through inspections are performed by representatives of the originating design group (nuclear engineering department during the operations phase) to ensure that the final installation of such items is in accordance with documents that formed the basis for the seismic analysis of the items.

3. During the construction phase, such items are neither identified as requiring the quality assurance requirements of 10CFR50, Appendix B, nor purchased to a code higher than normal system design dictates. During the operations phase, applicable procurement documents, design modification documents and station work orders will be reviewed by NQA for designation of appropriate quality assurance controls.

See Section 3.2.1 for further discussion of seismic design classification and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.30 Conformance to Regulatory Guide 1.30 (Safety Guide 30), Revision 0, August 11, 1972: Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment

HCGS complies with Regulatory Guide 1.30.

See Section 17.2 for further discussion of quality assurance and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.31 Conformance to Regulatory Guide 1.31, Revision 3, April 1978: Control Ferrite Content Stainless Steel Weld Metal (Prior to 2013)

Although Revision 3 of Regulatory Guide 1.31 is not applicable to HCGS, per its implementation section, HCGS complies with it, except as stated below.

Architect/Engineer procured items and field welding conform to Regulatory Guide 1.31, except as follows.

Contrary to Position C.1, C.2, and C.3 of Regulatory Guide 1.31, for HCGS, the procedure for determining the amount of delta ferrite in each heat or lot of austenitic stainless steel filler material is based on the chemical analysis provisions of ASME B&PV Code Section III, NE-2430, using the Schaeffler or DeLong diagrams represented by Figure NE-2433.1-1. Magnetic measurements are taken for comparative purposes only. A magnetic measurement of 3 percent delta ferrite (3 ferrite number) or less is cause to perform additional tests to determine the acceptability of the welding material.

Position C.4 of Regulatory Guide 1.31 is complied with for welding material certification to the extent that austenitic stainless steel welding filler materials used in the fabrication and installation of ASME B&PV Code, Section III components are controlled to deposit from 8 to 15 percent delta ferrite (8.5 to 18 ferrite number). Exceptions are 309 and 309L welding filler materials, which are determined by chemical analysis, are in accordance with the controlled to deposit from 5 to 15 percent delta ferrite (5 to 18 ferrite number) and are used only for welding carbon or low alloy steel to austenitic stainless steel.

Use of 309L welding filler material is required for the overlay deposit on the carbon or low alloy steel component nozzles or connecting pipe when postweld heat treatment is required. The specified delta ferrite ranges, as acceptable ferrite number range of 5 to 20.

See Section 5.2.3 for further discussion of ferrite control as it pertains to reactor coolant pressure boundary (RCPB) materials and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

Conformance to Regulatory Guide 1.31 Revision 4, October 2013: Control of Ferrite Content in Stainless Steel Weld Metal

Hope Creek Generating Station complies with Revision 4 of Regulatory Guide 1.31. Per this revision of the regulatory guide, ferrite content in the weld metal as depicted by a ferrite number (FN) of weld metal used in austenitic stainless steel core support structures, reactor internals, and class 1, 2 and 3 components should be between 5 and 20. The lower limit provides sufficient ferrite to avoid microfissuring in welds, whereas the upper limit provides ferrite content adequate to offset dilution and reduce thermal aging effects.

1.8.1.32 Conformance to Regulatory Guide 1.32, Revision 2, February 1977: Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Although Regulatory Guide 1.32 is not applicable to HCGS, per its implementation section, HCGS complies with IEEE 308-1974, as endorsed and modified by Regulatory Guide 1.32, subject to the clarification of Position C.1.b, C.1.d and C.1.f.

HCGS complies with Position C.1.b of Regulatory Guide 1.32 as discussed in Section 8.3.2.2.

Position C.1.d of Regulatory Guide 1.32 references Regulatory Guide 1.75. HCGS compliance to this Regulatory Guide is discussed in Section 1.8.1.75.

Position C.1.f of Regulatory Guide 1.32 references Regulatory Guide 1.9. HCGS compliance to this Regulatory Guide is discussed in Section 1.8.1.9.

See Chapter 8 for further discussion of the electrical system and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.33 Conformance to Regulatory Guide 1.33, Revision 2, February 1978: Quality Assurance Program Requirements (Operation)

HCGS complies with the Quality Assurance Program requirements of NQA-1-1994.

See the Quality Assurance Topical Report, Appendix C, Section 1.3.1.5 for further discussion.

1.8.1.34 Conformance to Regulatory Guide 1.34, Revision 0, December 28, 1972: Control of Electroslag Weld Properties

Regulatory Guide 1.34 is not applicable to HCGS because the process is not used.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.35 Conformance to Regulatory Guide 1.35, Revision 2, January 1976: Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures

Regulatory Guide 1.35 is not applicable because HCGS does not have a prestressed concrete containment.

1.8.1.36 Conformance to Regulatory Guide 1.36, Revision 0, February 23, 1973: Nonmetallic Thermal Insulation for Austenitic Stainless Steel

HCGS complies with Regulatory Guide 1.36.

See Section 5.2.3 for further discussion and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.37 Conformance to Regulatory Guide 1.37, Revision 0, March 16, 1973: Quality Assurance Requirements for Cleaning of Fluid System and Associated Components of Water Cooled Nuclear Power Plants

HCGS complies with NQA-1-1994 and the intent of the regulatory position set forth in the Regulatory Guide.

1.8.1.38 Conformance to Regulatory Guide 1.38, Revision 2, May 1977: Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water Cooled Nuclear Power Plants

HCGS complies with NQA-1-1994.

See the Quality Assurance Topical Report, Appendix C, Section 1.3.1.6 for further discussion.

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1.8.1.39 Conformance to Regulatory Guide 1.39, Revision 2, September 1977: Housekeeping Requirements for Water Cooled Nuclear Power Plants

HCGS complies with the requirements of NQA-1-1994.

See the Quality Assurance Topical Report, Appendix C, Section 1.3.1.7 for further discussion.

1.8.1.40 <u>Conformance to Regulatory Guide 1.40, Revision 0, March 16, 1973: Qualification Tests of Continuous Duty Motors Installed Inside the Containment of Water Cooled Nuclear Power Plants</u>

Regulatory Guide 1.40 and IEEE 334-1971 are not applicable to HCGS as there are no continuous duty Class 1E motors installed inside primary containment.

1.8.1.41 <u>Conformance to Regulatory Guide 1.41, Revision 0, March 16, 1973: Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments</u>

HCGS complies with Regulatory Guide 1.41.

For further discussion, see Sections 8.1.4 and 14.2.

1.8.1.42 <u>Conformance to Regulatory Guide 1.42, Revision 1, March 1974: Interim Licensing Policy On As Low As Practicable For Gaseous Radioiodine Releases From Light Water Cooled Nuclear Power Reactors</u>

Regulatory Guide 1.42 was withdrawn by the NRC on March 22, 1976.

HCGS is committed to Regulatory Guides 1.109, 1.111, and 1.112.

1.8.1.43 <u>Conformance to Regulatory Guide 1.43, Revision 0, May 1973: Control of Stainless Steel Weld Cladding of Low Alloy Steel Components</u>

Regulatory Guide 1.43 is not applicable to HCGS. Cladding on low alloy steel components is not used on safety-related components in the non-NSSS scope of supply.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.44 Conformance to Regulatory Guide 1.44, Revision 0, May 1973: Control of the Use of Sensitized Stainless Steel

HCGS complies with Regulatory Guide 1.44, except as noted below.

Architect/engineer procured items and architect/engineer field work comply with Regulatory Guide 1.44, subject to exceptions or clarifications stated below that are applied to ASME B&PV Code, Section III equipment and piping in safety-related systems. They are not generally applied to HVAC systems or to instruments.

Position C.1 of Regulatory Guide 1.44 is complied with since contamination of austenitic stainless steel (Type 300 series) by compounds that could cause stress corrosion cracking is avoided during all stages of fabrication and installation in accordance with Regulatory Guide 1.37 and ANSI N45.2.1-1973.

Nonmetallic materials in contact with austenitic stainless steel are controlled so that halogen and sulfur levels agree with the various Regulatory Guides or ANSI Standards covering these materials. In addition, these materials are removed immediately following the operation in which they are used and prior to any elevated temperature treatment. Penetrant materials may conform to the higher contaminant levels specified in Article 6, Section V, of the ASME B&PV Code, provided that the materials are thoroughly removed and the surface cleaned immediately after the examination has been completed. Crevices and small openings are protected from contamination.

Completed components are packaged such that they are protected from the weather, dirt, wind, water spray, and any other extraneous environmental conditions that may be encountered during shipment and subsequent site storage.

In the field, austenitic stainless steel components are stored clean and dry. Components either are stored indoors, or, if outdoors, are stored off the ground and covered with tarps.

Contamination of austenitic stainless steels in the field during installation is avoided as described above. The system hydrostatic test and the preoperational testing and final flushing of the completed system is performed with water equivalent to reactor coolant grade. Nonmetallic insulation composed of leachable chloride and fluoride materials that come into contact with austenitic stainless steel are held to the lowest practicable level by the inclusion of the requirements of Regulatory Guide 1.36 in the insulation purchase specifications.

Position C.2 of Regulatory Guide 1.44 is complied with since all grades of austenitic stainless steels (Type 300 series) are required to be furnished in the solution heat treated condition before fabrication or assembly into components or systems. The solution heat treatment varies according to the applicable ASME or ASTM material specification.

Position C.3 of Regulatory Guide 1.44 covers all austenitic stainless steels furnished in the solution heat-treated condition in accordance with the material specification. During fabrication and installation, austenitic stainless steels are not permitted to be exposed to temperatures in the range of 800 to 1500°F, except for welding and hot forming. Welding practices are controlled to avoid severe sensitization, and solution heat treatment in accordance with the material specification is also required following hot forming in the temperature range of 800 to 1500°F. Unless otherwise required by the material specification, the maximum length of time for cooling from the solution heat treated temperature to below 800°F is specified in the equipment specification. Corrosion testing in accordance with ASTM A 262-70, Practice A or E, may be required if the maximum length of time for cooling below 800°F is exceeded, or the solution heat-treated condition is in doubt.

No austenitic stainless steel is subjected to service temperatures in the range of 800 to 1500°F, as discussed in Position C.4 of Regulatory Guide 1.44. The only exposure of austenitic stainless steels to this range of temperatures occurs on the Containment

Hydrogen Recombiner System (CHRS) and subsequent to solution heat treating during welding. Welding practices are controlled as discussed below. In addition, the architect/engineer supplied austenitic stainless steel piping and valves that form part of the RCPB are fabricated either from L-grade wrought products or castings with controlled ferrite content.

During system testing of the recombiner system, the stainless steel does become sensitized. However, stress corrosion occurs only under the presence of condensation upon the metal surface. The formation of condensation is prevented by the use of a trickle treat system.

Heat treating austenitic stainless steel in the temperature range of 800 to 1500_F is not permitted and solution heat treatment is required following hot forming as discussed in Position C.5 of Regulatory Guide 1.44. Since sensitization is avoided, testing to determine susceptibility to intergranular attack is not performed.

Position C.6 of Regulatory Guide 1.44 covers welding practices that are controlled to avoid severe sensitization in the heat affected zone of unstabilized austenitic stainless steel, as described below. Unless otherwise stated, the position applies to both architect/engineer and architect/engineer suppliers and subcontractors. Intergranular corrosion testing is not performed on a routine basis.

The architect/engineer controls weld heat input during field installation by using shielded metal arc welding and gas tungsten-arc welding processes only. The size of electrodes for each process is limited to 5/32-inch and 1/8-inch diameter maximum, respectively, for welding non-L grade material, except for castings with controlled ferrite content. In addition to the above two processes, architect/engineer suppliers and subcontractors are permitted to use automatic submerged arc welding and gas metal arc welding. Hardsurfacing operations are not included. When automatic submerged arc welding or gas metal arc welding is used, or shielded metal arc welding or gas tungsten arc welding is used with electrodes larger than those specified above, testing in accordance with ASTM A262, Practice A or E, is required unless welding is followed by solution heat treatment.

The interpass temperature is controlled so as not to exceed 350°F. See Sections 5.2.3 and 6.1 for further discussion and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.45 Conformance to Regulatory Guide 1.45, Revision 0 May 1973: Reactor Coolant Pressure Boundary Leakage Detection Systems

HCGS is designed to comply with Regulatory Guide 1.45, with the exceptions, clarifications, and amplifications discussed below.

Paragraph C.3 of Regulatory Guide 1.45 requires that three methods of leak detection be provided. HCGS does not employ an airborne particulate radioactivity monitor due to uncertainties in detecting 1 gpm of RCPB leakage in 1 hour. The uncertainties that affect the reliability, sensitivity, and response times of radiation monitors, especially iodine and particulate monitors, are discussed below.

The amount of activity becoming airborne following a 1 gpm leakage from the RCPB varies, depending upon the leak location and the coolant temperature and pressure, which affect the flashing fraction and partition factor for iodines and particulates. Thus, an airborne concentration cannot be correlated to a quantity of leakage without knowing the source of the leakage.

Coolant concentrations during operation can vary by as much as several orders of magnitude within several hours. These effects are mainly due to spiking during power transients or changes in the use of the Reactor Water Cleanup (RWCU) System. An increase in the coolant concentrations can give increased containment concentrations when no increase in unidentified leakage occurs.

Not all activity is from unidentified leakage. Changes in other sources result in changes in the containment airborne concentrations. For example, identified leakage is piped to the drywell equipment drain sump, but all sump and collection drains are vented to the drywell atmosphere, thereby allowing particulates to escape, causing further measurement uncertainties.

The amount of activity that is detected depends upon the amount of plateout on drywell surfaces prior to reaching the detector intake. The amount of plateout is dependent on uncertain quantities, such as location of the leak, distance from the detectors, and the pathway to the detector.

Furthermore, under normal operating conditions a radiation-free background does not exist. There is a buildup of activity concentration due to both identified and unidentified leakage. At high equilibrium activity levels, a small change in activity level due to a small leak is hard to detect in the desired time interval.

Although particulate monitors are available with sensitivities covering concentrations expected in the drywell, previously discussed uncertainties under operating conditions coupled with any calibration and setpoint uncertainties make particulate monitors a less reliable method of leak detection.

HCGS does employ five separate and diverse leak detection methods. The RCPB leak detection system consists of:

1. Seismic Category I qualified drywell floor and equipment drain sump level monitors (in lieu of a Seismic Category I air particulate detection system).

2. A drywell cooler condensate flow monitor.

3. A noble gas monitor,

4. Seismic Category I drywell pressure monitors

5. Seismic Category I drywell temperature monitors.

Leakage flows into the drywell floor and equipment drain sumps are not measured directly due to physical configuration which makes it impractical to do so. As stated in Section 5.2.5.2, leakage flow into the sumps is calculated based on the rate of change of level in the sumps.

Sump pump starts and stops and duration of pumpout are monitored by the Class 1E radiation processor. An alarm is annunciated in the main control room whenever pumpout duration exceeds a predetermined time limit. Total sump pumpout can be calculated based on the duration of pumpout and the constant known flowrate of the sump pump provided that only one pump is required to lower the sump level. The starting of the second pump is a positive indication of excessive leakage into the sump or is an indication that the first pump has failed with either event requiring operator action. The high-high level condition which initiated the operation of the second pump is annunciated in the main control room.

Paragraphs C.2 and 5 require that the leakage monitors be able to detect an increase in leakage of 1 gpm in 1 hour. The noble gas monitor can detect concentrations as low as 10^{-6} μCi/cc, the minimum activity concentration expected in the drywell based on the primary system coolant. However, an increase in 1 gpm leakage within an hour may be difficult to detect due to high equilibrium activity levels for noble gases (10^{-6} to 10^{-4} μCi/cc) and buildup of background radiation. The noble gas monitor is capable of detecting leaks of approximately 10 gpm and does so very quickly due to the high diffusion rates of the noble gases.

The drywell floor drain sump level monitor and the drywell cooler condensate monitor can detect fluid flows of 1 gpm in 1 hour. However, fluid flow is not always a direct indication of RCPB leakage because of free communication between the suppression chamber and the drywell. The drywell atmosphere is not necessarily saturated due to the water vapor removal by the drywell coolers. Hot water can evaporate from the torus and enter the drywell. The water will condense and register on the drywell cooler condensate monitor. The condensate drains into the drywell floor drain sump and will register on the sump level monitor. Therefore, during times of suppression pool transients, such as from heat up from main steam safety/relief valve (SRV) or HPCI system testing, evaporation from the suppression chamber will obscure values of RCPB leakage.

Position C.7 requires that indicators and alarms for each leakage detection system should be provided in the main control room. Procedures for converting various indications to a common leakage equivalent should be available to the operators. The calibration of the indicators should account for needed independent variables.

Position C.7 is further clarified by Standard Review Plan Section 5.2.5, III.5 which requires that if monitoring is computerized, backup procedures should be available to the operator.

The drywell air coolers leakage monitoring and noble gas monitoring systems signals are processed by local radiation processors which then transmit the processed data to the main control room via the central radiation processor (CRP). The CRP in turn makes this indicating and alarming information available to the control room operator via CRT displays.

These signals are processed locally by local radiation processors (LRPS) which are provided with digital readout indicators. These indicators provide information to the operator in the same format (using the same engineering units) as the information provided by the CRP through the CRTs in the main control room. Since these indications are of the same format, procedures for converting the LRP indication to a common leakage equivalent (to that normally provided in the main control room) are unnecessary.

As described in Section 5.2.5.2, displays of drywell equipment and floor drain sump levels (which are not dependent on the non-1E plant computer systems) are provided on panel 10C604 in the main control room.

Position C.8 requires that the leakage detection systems should be equipped with provisions to readily permit testing for operability and calibration during plant operation. This is interpreted to mean channel functional testing as defined in the Technical Specifications (Section 16). Calibration of the leakage detection systems is performed during plant outages per the technical specifications. Calibration of the drywell floor and equipment drain sump level monitoring systems can not be performed at power due to the fact that the sensors are located inside the drywell and are therefore inaccessible during power operation. Rosemount 1153 transmitters are used throughout the plant and are typically calibrated on an 18 month cycle (reference NUREG-0123). This model transmitter is used for the sump level transmitter. In addition, the calibration accuracy of these transmitters can be observed on an ongoing basis by comparing the level readings with known independently measured sump levels at which the sump pumps start or stop. The pumps are started and stopped using electromechanical float switches. It should also be noted that the rate of change readings (sump inflow) obtained from these transmitters will be substantially free from the effects of drift due to the sampling frequency. The sensors for the drywell cooler condensate flow monitoring systems and the drywell temperature monitoring system are also located inside the drywell (and therefore inaccessible during power operation). However, these sensors are LT's and access to them for normal instrument channel calibration is not required. The remaining leak detection monitoring systems discussed above have the capability of being calibrated during operation.

For further discussion of the RCPB Leak Detection System, see Section 5.2.5.

1.8.1.46 <u>Conformance to Regulatory Guide 1.46, Revision 0, May 1973: Protection Against Pipe Whip Inside Containment</u>

Although NRC Regulatory Guide 1.46 was withdrawn by the NRC on March 11, 1985, HCGS commitments, as stated below, are not affected by this withdrawal.

The criteria set forth in Regulatory Guide 1.46 are design bases for HCGS. See Section 3.6.2 for further discussion of pipe break design and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.47 <u>Conformance to Regulatory Guide 1.47, Revision 0, May 1973: Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems</u>

HCGS complies with Regulatory Guide 1.47.

For further discussion of bypass and inoperable status indication, see Sections 7.2, 7.3, 7.4, 7.5 and 7.6.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.48 <u>Conformance to Regulatory Guide 1.48, Revision 0, May 1973: Design Limits and Loading Combinations for Seismic Category I Fluid System Components</u>

The information and requirements of Regulatory Guide 1.48 have been superseded by NUREG-0800, Section 3.9.3, Appendix A, Revision 1, July 1981.

For further discussion of mechanical component design, see Section 3.9.

1.8.1.49 <u>Conformance to Regulatory Guide 1.49, Revision 1, December 1973: Power Levels of Nuclear Power Plants</u>

HCGS complies with Regulatory Guide 1.49.

For further discussion, see Section 15.0.4 and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.50 Conformance to Regulatory Guide 1.50, Revision 0, May 1973: Control of Preheat Temperature for Welding of Low-Alloy Steel

HCGS complies with Regulatory Guide 1.50 subject to exceptions and clarifications added below.

Position C.1.a of Regulatory Guide 1.50 requires minimum preheat temperatures (Appendix D of ASME B&PV Code, Section III), regardless of whether impact testing is required. When impact testing is required, the requirements of Subarticle 2300 of ASME B&PV Code, Section III, and Regulatory Guide 1.50 are met. The maximum interpass temperature is 500°F unless otherwise specified. When impact testing is not required, specification of a maximum interpass temperature in the welding procedure is not necessary to ensure that the required mechanical properties are met.

Position C.1.b of Regulatory Guide 1.50 is not complied with since the welding procedure qualification requirements of ASME B&PV Code, Section III and IX, are considered to be more than adequate.

With respect to Position C.2 of Regulatory Guide 1.50, usage of low alloy steel in piping, pumps, and valves is minimal and primarily limited to Class 3 construction. When low alloy steel piping, pumps, and valves are used, preheat is maintained until welding is completed but not until postweld heat treatment is performed, since the conditions that cause delayed cracking in the weld or heat affected zone (HAZ) are not present.

Position C.4 of Regulatory Guide 1.50 is complied with when the Positions C.1 and C.2 are not met.

For further discussion of RCPB and equipment safety feature (ESF) materials, see Sections 5.2.3 and 6.1.1.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.51 Conformance to Regulatory Guide 1.51, Revision 0, May 1973: Inservice Inspection of ASME Code Class 2 and 3 Nuclear Power Plant Components

Regulatory Guide 1.51 was withdrawn by the NRC on July 15, 1975. For discussion of inservice inspection, see Sections 3.9.6, 5.2.4, and 6.6.

1.8.1.52 Conformance to Regulatory Guide 1.52, Revision 2, March 1978: Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants

HCGS complies with Regulatory Guide 1.52, except as stated below:

1. Position C.2.a of Regulatory Guide 1.52 - This position lists the sequence of components that should make up engineered safety feature ESF atmospheric cleanup systems. In the HCGS design, the FRVS vent units do not have demisters, and there are no high efficiency particulate air (HEPA) filters ahead of the carbon adsorbers because the FRVS vent units are downstream of the demisters and HEPA filters in the recirculation units. Each of the FRVS vent trains receives all its air from the discharge of the FRVS recirculation trains. Therefore, demisters for the FRVS vent trains are not required.

   The control room emergency filters are not provided with demisters because moisture impingement and water damage is not considered a potential problem. The units recirculate air from the main control room with minimal outside air.

Each of the CREF trains draws a mixture of 1000 cubic feet per minute (CFM) outside air (assumed 100 percent RH) and 3000 CFM room air (50 percent RH) resulting in a mixed air relative humidity at 62 percent. A heating coil is provided for humidity control. Air entering the charcoal filters is expected to be less than 70 percent relative humidity. Sources of excess moisture do not exist which could cause saturated or super saturated mixed air conditions. Therefore, demisters are not required for water droplet removal.

2. Position C.2.g of Regulatory Guide 1.52 - This position requires that the pertinent pressure drops and flow rates on ESF atmosphere cleanup systems be alarmed and recorded in the control room. On the FRVS recirculation units, the pertinent pressure drop, which is instrumented to signal an alarm and record in the main control room, is the pressure drop across the upstream HEPA filters. In addition to this, the pressure drop across the entire filter train is alarmed in the control room, and local differential pressure indication across each filter component is provided. On the CREF units the pertinent pressure drop is the pressure drop across the upstream HEPA filters. This is instrumented to indicate and activate an alarm in the control room and is available in the plant computer. In addition to this, local differential pressure indication across each filter component is provided. CREF and FRVS compliance with minimum instrumentation requirements is provided in Tables 6.5-4 and 6.8-5, respectively.

3. Position C.2.j. of Regulatory Guide 1.52 - Overall design considerations include reduction of radiation exposures during routine maintenance and testing. It is not anticipated, however, that workers will handle filter units immediately after a DBA. Accordingly, no efforts

are made to provide a unitized atmosphere cleanup train design specifically to facilitate post-accident removal.

4. Position C.2.1 of Regulatory Guide 1.52 - Table 4-3 of ANSI N509-1980 Section 4.12 was used as the acceptance criteria for maximum allowable leakage in ductwork.

5. Position C.3.o of the Regulatory Guide 1.52 - Unusual air flow straightening devices are not installed. Adequate flow distribution is achieved in a low air velocity housing without special devices.

6. The guidance on spacing between components is not followed for HCGS. Spacing between components may be less than 3 feet where anticipated maintenance does not require this clearance.

7. Regulatory Guide 1.52 references ANSI N510-1975. HCGS testing commitments will follow the ANSI N510-1980 issue.

8. Position C.4.d of Regulatory Guide 1.52 - This position requires the heaters to be on during the 10 hour adsorber and HEPA filter drying run. For Hope Creek, heaters on is considered to be equivalent of heaters dissipating heat.

1.8.1.53 <u>Conformance to Regulatory Guide 1.53, Revision 0, June 1973: Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems</u>

HCGS complies with IEEE 379-1972, as endorsed and modified by Regulatory Guide 1.53.

See Section 8.1.4.10 for further discussion of compliance with Regulatory Guide 1.53 and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.54 <u>Conformance to Regulatory Guide 1.54, Revision 0, June 1973: Quality Assurance Requirements for Protective Coatings Applied to Water Cooled Nuclear Power Plants</u>

HCGS complies with the requirements and guidelines of ANSI N101.4-1972, as endorsed and modified by Regulatory Guide 1.54, for protective coating applications requiring quality assurance in accordance with 10CFR50, Appendix B.

See Section 6.1.2 for further discussion of ESF materials and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.55 Conformance to Regulatory Guide 1.55, Revision 0, June 1973: Concrete Placement in Category I Structures

Regulatory Guide 1.55 was withdrawn by the NRC on July 21, 1981. However, the placement of concrete in Seismic Category I structures is in accordance with this Regulatory Guide, with the exceptions discussed below.

Positions C.2 and C.3 state the presumed functional responsibilities of the "designer" and the "constructor." The designer's role includes the responsibilities of checking shop drawings and locations of construction joints. For HCGS, the former is fully delegated to the qualified architect/engineer/constructor although the architect/engineer design engineering office may check significant portions and may advise construction accordingly. The responsibility for construction joint location is partially delegated to the field in the sense that the field must follow the guidelines set out in the design drawings and specifications prepared by engineering.

For further discussion of the design of Seismic Category I structures, see Section 3.8.

This Regulatory Guide is not applicable during the operations phase.

1.8.1.56 Conformance to Regulatory Guide 1.56, Revision 1, July 1978: Maintenance of Water Purity in Boiling Water Reactors

HCGS complies with Regulatory Guide 1.56, with exception to Position C.4.c. This exception is discussed in Section 10.4.6.2.1.

For further discussion, see Sections 5.2.3, 5.4.8, and 10.4.6.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.57 Conformance to Regulatory Guide 1.57, Revision 0, June 1973: Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components

HCGS complies with Regulatory Guide 1.57, except that the loading combinations and stress limits of Position C.1.b(2) are not used. The loading combinations and stress limits that are used by HCGS in the analysis of the primary containment during a postulated post-LOCA flooded condition are recognized by Standard Review Plan Section 3.8.2, Paragraph II.3.b.iii.e.

1.8.1.58 Conformance to Regulatory Guide 1.58, Revision 1, September 1980: Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel

NRC Regulatory Guide 1.58 was withdrawn by the NRC on July 31, 1991. HCGS is committed to the requirements of NQA-1-1994.

1.8.1.59 Conformance to Regulatory Guide 1.59, Revision 2, August 1977 with Errata Sheet July 30, 1980: Design Basis Floods for Nuclear Power Plants

Although Regulatory Guide 1.59 does not apply to HCGS, per its implementation section, HCGS complies with it.

For further discussion of flood design, see Section 2.4.2.

1.8.1.60 Conformance to Regulatory Guide 1.60, Revision 1, December 1973: Design Response Spectra for Seismic Design of Nuclear Power Plants

HCGS complies with Regulatory Guide 1.60.

For further discussion of the seismic design, see Section 3.7.1.

1.8.1.61 Conformance to Regulatory Guide 1.61, Revision 0, October 1973: Damping Values for Seismic Design of Nuclear Power Plants

HCGS complies with Regulatory Guide 1.61.

See Section 3.7.1 for further discussion of seismic design and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.62 Conformance to Regulatory Guide 1.62, Revision 0, October 1973: Manual Initiation of Protective Actions

HCGS complies with Regulatory Guide 1.62, except as noted below.

Position C.1 states that means should be provided for manual initiation of each protective action at the system level. This position requires that the steam isolation dampers, as shown on Plant Drawing M-84-1, for the heating and ventilation systems serving areas of the Reactor Building that enclose high energy lines, be capable of manual actuation from the main control room. However, there are two redundant automatic isolation dampers in series with separate and redundant power supplies.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.63 Conformance to Regulatory Guide 1.63, Revision 2, July 1978: Electric Penetration Assemblies in Containment Structures for Light Water Cooled Nuclear Power Plants

Although Regulatory Guide 1.63 is not applicable to HCGS, per its implementation section, HCGS complies with the design, qualification, construction, installation, and testing requirements of IEEE 317-1976, as modified by Regulatory Guide 1.63, subject to the clarification in Section 8.1.4.12.

1.8.1.64 Conformance to Regulatory Guide 1.64, Revision 2, June 1976: Quality Assurance Requirements for the Design of Nuclear Power Plants

NRC Regulatory Guide 1.64 was withdrawn by the NRC on July 31, 1991. HCGS is committed to the requirements of NQA-1-1994.

1.8.1.65 Conformance to Regulatory Guide 1.65, Revision 0, October 1973: Materials and Inspections for Reactor Vessel Closure Studs

Regulatory Guide 1.65 is not applicable.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.66 Conformance to Regulatory Guide 1.66, Revision 0, October 1973: Nondestructive Examination of Tubular Products

Regulatory Guide 1.66 was withdrawn by the NRC on September 28, 1977.

See Section 5.2.3 for further discussion of testing on mechanical components and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.67 Conformance to Regulatory Guide 1.67, Revision 0, October 1973: Installation of Overpressure Protection Devices

Regulatory Guide 1.67 is not applicable to HCGS because there are no open discharge lines where reaction forces are considered to be significant.

1.8.1.68 Conformance to Regulatory Guide 1.68, Revision 2, August 1978: Initial Test Programs for Water Cooled Nuclear Power Plants

HCGS complies with Regulatory Guide 1.68, with the exceptions and clarifications discussed below.

Position C.1 provides the criteria for selection plant features that are tested during the initial test program. At HCGS, testing is conducted on structures, systems, components, and design features as described in Section 14.2, based on their safety-related functions.

See Section 3.9.2 for further discussion of dynamic testing and analysis.

The objective of Regulatory Guide 1.68 is to describe the scope and depth of a test program, as required, to ensure that plant structures, systems, and components perform satisfactorily in service. The basis for this Regulatory Guide is Appendix B to 10CFR50, which specifically applies only to testing the performance of safety-related functions. Therefore, this Regulatory Guide is applied only to plant structures, systems, and components that have safety-related functions, defined as those plant features necessary to ensure the integrity of the RCPB, the capability to shut down the reactor and maintain it in a safely shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in offsite exposures comparable to the guideline exposure of 10CFR50.67.

Safety-related structures, systems, and components are identified as such in Chapter 14 and are tested to meet the requirements of Regulatory Guide 1.68. Other systems and components within the plant that are not safety-related may or may not be tested in accordance with the Regulatory Guide. Since the plant units that are not safety-related by definition do not compromise the safety-related aspects of the plant, it is not planned to test them to the Regulatory Guide.

Regulatory Position C.7 and Section 1.h of Appendix C state that one of the objectives of the initial test program is to verify by trial use that the facility operating and emergency procedures are adequate. Because preoperational test procedures are intended to demonstrate system design criteria, they are conducted under system configurations and conditions different than those required by facility operating and emergency procedures. Therefore, operating and emergency procedures are proven independent of the preoperational test procedures.

Section 1 of Appendix A states that system vibration, expansion, and restraints may be verified by observation as allowed during power-ascension testing by Section 5.0.0 of Appendix A. This position statement does not apply to the vibration monitoring of reactor internals.

Section 1.1 of Appendix A states that spiked samples should be used where necessary to verify the operability of radioactive waste handling and storage systems. The functional testing of these systems is accomplished without the use of spiked samples of typical media, use of which is also not considered necessary to verify conformance to the design.

1. Appendix A, Paragraph 1.a(1), 1.1.(1), 1.e - General Electric BWRs have performed hot functional tests during initial heatup following fuel load. System expansion, hanger, seismic, and restraint checks not performed prior to fuel load will be performed during the initial heatup after fuel load. Prior to nuclear heatup and plant operation, there is no practical mechanism to accomplish integrated system heatup on the reactor coolant system, main steam system, feedwater system, steam extraction system, and HPCI/RCIC steam lines. Therefore, the expansion tests are deferred to Phase III startup testing. The Section 14 test descriptions associated with expansion testing following fuel load are Sections 14.2.12.3.15 and 14.2.12.3.39. The systems subject to expansion testing are discussed in Section 3.9.2. Figures 14.2-4 and 14.2-5 describe when expansion testing will be performed.

2. Appendix A, Paragraphs 1.a(3), 4.s, 5.p - Regulatory Guide 1.20, Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing, is addressed in Section 1.8.1.20. Hope Creek is a Regulatory Guide 1.20 Non-Prototype, Category 1

plant. Therefore, Hope Creek will implement the inspection program as permitted by Paragraph 3.1.2 of Regulatory Guide 1.20. During the preoperational test phase, the reactor internals will be inspected following flow through the vessel as part of the standard BWR test program. No further testing is planned following fuel load. Paragraph 2.2.2.C of Regulatory Guide 1.20 states that the vibration test may be conducted without fuel assemblies (or dummy assemblies) if it can be shown by analytical or experimental means that such conditions yield conservative results. The study of prototype test data by General Electric (refer to Reference 3.9-12) has shown vibration response amplitudes are conservative in preoperational test conditions as compared to operating conditions. Therefore, HCGS will perform the preoperational phase inspection program with no fuel assemblies (rated volumetric flow for 35 hours balanced two loop operation and single loop flow for 16 hours each loop with pre and post vessel internal inspections).

3. Appendix A, Paragraph 1.b(3) - Verification of proper mixing of the solution is not performed as part of the preoperational test program. Just prior to fuel load, the solution is mixed and sampled using the station operating procedures.

4. Appendix A, Paragraph 1.c - Compliance with Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems, is addressed in Section 1.8.1.118. Regulatory Guide 1.118 will be used as guidance for preoperational tests.

5. Appendix A, Paragraph 1.d - Compliance with Regulatory Guide 1.41, Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments, is addressed in Section 1.8.1.41.

6. Appendix A, paragraph 1.e - Compliance with Regulatory Guide 1.68.1, Preoperational and Initial Startup Testing of Feedwater and Condensate System for BWR Plants, is addressed in Section 1.8.1.68.1.

7. Appendix A, Paragraph 1.g(2) - Emergency loads are tested with nominal voltage available at the emergency ac power distribution system buses. The power source to these buses is either from offsite (normal) or onsite (standby). When the bus is supplied from the onsite source, the available voltage is maintained within specified limits to verify proper functioning and loading of the onsite source. Test abstracts are presented in Sections 14.2.12.1.30, 14.2.12.1.32 and 14.2.12.1.33. Testing of emergency loads with maximum and minimum design voltage available is not considered necessary because the station distribution system is designed to maintain voltages to support starting and operating of loads within their design limits. The station distribution system has been analyzed in accordance with BTP PSB-1 to establish minimum and maximum voltages under several operating conditions with only the offsite source considered available. Actual test voltage at selected points on the station distribution system will be taken and compared with the calculated voltages to validate the analysis performed.

8. Appendix A, Paragraph 1.g(3) - Compliance with Regulatory Guide 1.108, Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants, is addressed in Section 1.8.1.108.

   Compliance with Regulatory Guide 1.9, Selection, Design and Qualification for Diesel Generator Units Used as Onsite Electric Power System at Nuclear Power Plants, is addressed in Section 1.8.1.9.

9. Appendix A, Paragraph 1.h(10) - There is no practical way to verify the maximum heat removal capability of the UHS. Flow paths are demonstrated to show the proper operation of equipment and structures used to transport the water to and from the UHS. The ultimate heat sink (UHS) is the Delaware River, which provides the source of cooling water to the SACS heat exchangers through the Station Service Water System (SSWS). The UHS has been designed in accordance with the requirements of Regulatory Guide 1.27 and is described in Sections 9.2.5 and 9.2.1. The UHS has been designed to perform during periods of adverse meteorological conditions which result in maximum water consumption and minimum cooling capability as stated in Section 9.2.5.1.2. Therefore, it is not practical to verify the maximum heat removal capability of the UHS.

   A description of tests for station service water and safety auxiliaries cooling systems to deliver cooling water to their components is provided in Sections 14.2.12.1.12 and 14.2.12.1.16, respectively. Also a description of the test to demonstrate that safety auxiliaries cooling system performance margin is adequate to support engineered safety features equipment over their full range of design requirements is provided in Section 14.2.12.3.38.

   Performance test for each service water pump was conducted and performed in accordance with approved HTPCo procedures for the test and in accordance with the ASME Power Test Code 8.2, 1965 and the standards of the Hydraulic Institute. The pump was tested with the bell submerged 4 feet 6 inches below the design water level which is 76 feet 0 inches (In addition, Hope Creek Technical Specifications require a plant shutdown at 80 feet PSE&G datum.). Test demonstrated adequate net positive suction head and absence of vortexing at the minimum postulated river level, which is 81 feet 0 inches. Model studies were conducted at Lasalle Hydraulic Lab to ensure acceptable conditions in the pump sump. The measures suggested in the test, were taken in order to avoid vortices.

10. Appendix A, Paragraph 1.h(7) - Compliance with Regulatory Guide 1.52, Design, Testing and Maintenance Criteria for Engineered Safety Feature Atmospheric Cleanup System of Light Water Cooled Nuclear Power Plants, is addressed in Section 1.8.1.52.

11. Appendix A, Paragraphs 1.k(2) & (3) - Preoperational testing of personnel radiation monitoring and survey equipment or laboratory equipment is not performed. Calibration tests are performed prior to core load in accordance with station procedures.

12. Appendix A, Paragraphs 1.m(4) & 1.0(1) - Regulatory Guide 1.104 was withdrawn by the NRC on August 22, 1979. During preoperational testing, the cranes will be verified to function in accordance with specifications. The controls, interlocks, and travel limits of the reactor building and fuel handling cranes are verified.

13. Appendix A, Paragraph 1.n(11) - Compliance with Regulatory Guide 1.80, Preoperational Testing of Instrument Air Systems, is addressed in Section 1.8.1.80.

14. Appendix A, Paragraph 2.c - The Reactor Protection System will be functionally checked in accordance with the HCGS Technical Specification prior to initial criticality using station surveillance and calibration procedures. The Reactor Protection System is shown to operate in conjunction with the control rod drive startup test,

described in Section 14.2.12.3.8. Also, the Reactor Protection System is verified to operate following scheduled transient tests such as MSIV isolation and turbine trip/generator load rejection.

15. Appendix A, Paragraph 5.0 - Setpoints related to leak detection high steam flow in HPCI and RCIC are determined and set as stated in Sections 14.2.12.3.12 and such as drywell equipment drain sump pump will be accomplished using station operating procedures.

16. Appendix A, Paragraph 2.e - Compliance with Regulatory Guide 1.56, Maintenance of Water Purity in Boiling Water Reactors, is addressed in Section 1.8.1.56.

17. Appendix A, Paragraph 4.m - Following fuel load, there is no planned startup test of the MSIV leak control system. The preoperational test demonstrates the operability of the system at design conditions. Testing following fuel load does not contribute any additional meaningful data. The HCGS sealing system is a positive pressure system not a vacuum system. A vacuum system's operation could be affected by hot steam pipe because this could elevate the temperature of the vacuum system. In contrast, hot steam pipe will have no affect on the operation of a positive pressure system that "pumps" sealing gas into the steam pipe rather than "pumping" gas out of the steam pipe. Therefore, testing the HCGS system at ambient temperatures should be sufficient.

18. Appendix A, Paragraph 4.p - Main steam system relief valve testing will be performed at a power level between 10 and 20 percent of rated thermal power in order to provide adequate control of system pressure.

19. Appendix A, Paragraph 5.j - Rod runback and partial scram testing is not performed because the plant does not have this design feature.

20. DELETED

21. Appendix A, Paragraph 5.q - There are no startup tests of the failed fuel detection systems. Preoperational testing and periodic surveillance testing after fuel load ensure the proper operation of radiation monitoring systems used for isolation signals in case of gross fission product release. Data is recorded from these systems and used as baseline data. There will be no Phase III Startup Test entitled "Failed Fuel Detection System". Two systems at Hope Creek routinely monitor gaseous activities which result from fission product release from the fuel: the Main Steam Process Radiation Monitoring subsystem, and the Offgas Radiation Monitoring subsystem. Startup test procedure No. 1, Chemical and Radiochemical, states that gaseous activities will be measured at each major power level plateau, as defined in Figures 14.2-4 and 14.2-5. The test method has been revised to state that baseline data will be documented (Section 14.2.12.3.1).

22. Appendix A, Paragraph 5.s - Although there will be no startup test procedure designated hotwell level control, operation of the hotwell level control system will be verified using station operating procedures and monitoring hotwell level during Phase III startup testing.

23. Appendix A, Paragraph 5.dd - Compliance with Regulatory Guide 1.68.2, Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water Cooled Nuclear Power Plants, is addressed in Section 1.8.1.68.2.

24. Appendix A, Paragraph 5.gg - The ATWS subsystems are thoroughly checked out logically and functionally during the preoperational test program, as described in Sections 14.2.12.1.2.c.6, 14.2.12.1.3.c.3, 14.2.12.1.4.c.4, 14.2.12.1.8.c.9, 14.2.12.1.9.c.7, and 14.2.12.1.10.c.4. The recirculation pump trip (RPT) is tested as part of the recirculation system tests and generator/turbine trips that are performed in Phase III testing.

25. Appendix A, Paragraph 5.ii - Hope Creek design does not incorporate the recirculation flow control valve.

26. Appendix A, Paragraph 4.o - For the purpose of initial turbine generator testing conducted in the Low Power Testing program the nominal 5 percent power limitation will be extended to 10 percent power. All other low power testing will be conducted within the 5 percent power limitation.

1.8.1.68.1 Conformance to Regulatory Guide 1.68.1, Revision 1, January 1977: Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants

HCGS complies with the intent of Regulatory Guide 1.68.1. For further discussion of the initial test program, see Section 14.

1.8.1.68.2 Conformance to Regulatory Guide 1.68.2, Revision 1, July 1978: Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants

HCGS complies with the intent of Regulatory Guide 1.68.2.

For further discussion of the initial test program, see Section 14.

1.8.1.68.3 <u>Conformance to Regulatory Guide 1.68.3, Revision 0, April 1982: Preoperational Testing of Instrument and Control Air Systems</u>

HCGS complies with Regulatory Guide 1.68.3, with the following exceptions and clarifications discussed below:

1. Deleted

2. Position C.5 - Observation of branch line pressure during maximum system service is sufficient to ensure that total air demand is in accordance with system design.

2.1 Position C.6 - The Instrument Air System afterfilter is designed to remove 0.04 micrometer particles with 98 percent efficiency. The system is designed to permit preventive or corrective maintenance on one dryer and afterfilter train without affecting system operability. Therefore, quarterly replacement of the afterfilter assures that the maximum particle size in the air stream at the instrument is 5.0 micrometers.

3. Positions C.7 and 8 - Each safety-related component is tested on an individual basis to ensure that the subject component responds safely to all failure modes.

4. Position C.10 - All safety-related air operated loads either fail to their safe position on loss of instrument air or are provided with an accumulator which ensures operation following a loss of air condition. Each safety-related component is tested on an individual basis

to ensure that the subject components respond safely to a failure mode. Safety-related components are verified for proper operation during loss of instrument air in accordance with Section 14.2.12.1.27.c.4.

5. Position C.11 - The instrument air system is provided with pressure relief valves which ensure that no safety-related components will be subjected to air pressure above their design value. Instrumentation has been provided to automatically trip compressors upon high air pressure in the receiver. Relief valve setpoints will be checked and instrumentation calibration completed prior to performing the preoperational test in accordance with Section 14.2.12.1.27.

1.8.1.69 Conformance to Regulatory Guide 1.69, Revision 0, December 1973: Concrete Radiation Shields for Nuclear Power Plants

HCGS complies with ANSI N101.6-1972, as endorsed and modified by Regulatory Guide 1.69.

For further discussion of concrete shielding, see Section 12.3.2.

1.8.1.70 Conformance to Regulatory Guide 1.70, Revision 3, November 1978: Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, LWR Edition

The HCGS FSAR conforms to the format and content requirements of Regulatory Guide 1.70 with the following clarification:

The FSAR was written in accordance with the guidance of Regulatory Guide 1.70, Revision 3. Additionally, PSEG Nuclear will utilize Regulatory Guide 1.181 in conjunction with NEI 98-03, Guideline for Updating Final Safety Analysis Reports, as guidance for maintaining the UFSAR in accordance with the requirements of 10 CFR 50.71(e).

1.8.1.71 Conformance to Regulatory Guide 1.71, Revision 0, December 1973: Welder Qualification for Areas of Limited Accessibility

HCGS complies with Regulatory Guide 1.71, subject to the exceptions and clarifications described below.

Position C.1 states that the performance qualification should require testing of the welder under simulated restricted access conditions. At HCGS, performance qualifications for personnel who weld under conditions of limited access, as defined in Position C.1 of Regulatory Guide 1.71, are conducted in accordance with the applicable requirements of ASME B&PV Code, Sections III and IX. Additionally, responsible site supervisors are required to assign only the most highly skilled welders to limited access welding. Welding conducted in areas of limited access is subjected to the required nondestructive testing and no waiver or relaxation of examination methods or acceptance criteria because of the limited access is permitted.

Position C.2 of Regulatory Guide 1.71 requires requalification when significantly different restricted accessibility conditions occur or when any of the essential welding variables in Section IX changes. At HCGS, requalification is required whenever any of the essential variables of ASME B&PV Code, Section IX, are changed, or when any authorized inspector questions the ability of the welder to perform the requirements of ASME B&PV Code, Sections III or IX satisfactorily.

Concerning Position C.3, production welding is monitored and welding qualifications are certified in accordance with Positions C.1 and C.2.

See Section 5.2.3, Chapter 17, for further discussion of welding procedures and quality assurance and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.72 Conformance to Regulatory Guide 1.72, Revision 2, November 1978: Spray Pond Piping Made From Fiberglass Reinforced Thermosetting Resin

Regulatory Guide 1.72 is not applicable to HCGS because HCGS does not use a spray pond for its UHS.

1.8.1.73 Conformance to Regulatory Guide 1.73, Revision 0, January 1974: Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

HCGS complies with IEEE 382-1972, as endorsed and modified by Regulatory Guide 1.73, subject to the exceptions and clarifications described below.

Valve motor actuators may be qualified by either analysis and successful use under similar conditions, or by actual type tests, as permitted by Section III of Appendix B to 10CFR50.

Where type tests are proposed by a manufacturer, IEEE 382-1972, together with the specified accident environment, is used as the basis for evaluating the test program.

See Section 3.11 for further discussion of environmental qualification of electrical equipment and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.74 Conformance to Regulatory Guide 1.74, Revision 0, February 1974: Quality Assurance Terms and Definitions

NRC Regulatory Guide 1.74 was withdrawn by the NRC on September 1, 1989. HCGS complies with the requirements of NQA-1-1994.

1.8.1.75 Conformance to Regulatory Guide 1.75, Revision 2, September 1978: Physical Independence of Electric Systems

HCGS complies with IEEE 384-1974, as modified and endorsed by Regulatory Guide 1.75, Revision 2, with the clarifications and exceptions outlined below.

Position C.1 electrical separation is accomplished at HCGS per IEEE 384-1992 which was endorsed by Regulatory Guide 1.75 Rev. 3. This revision states, "The breaker or fuse that is automatically open by fault current may be used as an isolation device...." HCGS use of isolation devices are used as defined in this standard. Isolation devices that are actuated only by a fault current are coordinated such that upstream circuit protection devices are not affected by a non-Class 1E fault. Where fuses are used as isolation devices, two series Class 1E fuses are used to provide additional assurance that non-Class 1E faults do not propagate to the Class 1E bus.

Position C.1 separation is accomplished in general by supplying non-Class 1E loads connected to a Class 1E bus through a single breaker with a shunt trip device tripped by a LOCA signal. In these cases, non-Class 1E loads will be tripped automatically by LOCA signal. Provisions for restoring certain of these loads from the main control room are provided.

For normal (non-accident) conditions, the breakers which are Class 1E and are equipped with overcurrent protective devices, will trip on fault currents in the non-Class 1E loads such that the Class 1E buses remain functional. The breakers' LOCA trip function and overcurrent protective devices are periodically tested during plant operation to ensure operability.

This method of meeting Position C.1 ensures that the ESF, RPS and NMS electrical and physical separation requirements are maintained. The cables beyond the breakers are non-Class 1E and are not run in the same raceways as the divisionalized cables of the ESF systems, RPS, and NMS. Section 8.1.4.14.1 indicates that the raceways for the ESF systems, RPS, and NMS are separate and independent of each other and are separated from non-Class 1E circuits.

The remaining clarifications and exceptions are associated with Regulatory Guide 1.75, Revision 2, and IEEE Std. 384-1974.

Position C.6 states that all analyses to justify lesser separation distances shall be identified. The following are the HCGS exceptions to the IEEE 284 separation distances.

A. There are six generic cases where analysis and/or test data are used to justify lesser separation distances. These are identified and analyzed as follows:

   1. Conduit to conduit less than one (1) inch apart.

      Because of space limitations in some areas of the plant, the minimum separation distance of one inch between rigid steel conduits can not be maintained. The use of the conduits is limited to instrumentation to instrumentation control to control, and instrumentation to power feeder with maximum 120 V ac or 125 V dc cables only. Wyle Test Report No. 56719, prepared for Susquehanna Steam Electric station, showed that rigid steel conduits in contact with each other are acceptable barriers. The testing demonstrated that shorting of conductors in one conduit until failure did not affect the performance of the conductors in the other conduit or damage the conduit. In addition, Franklin Institute Research Laboratories (FIRL) performed similar testing for the Toledo Edison Company in 1977 with successful results. The test configuration and cables used conservatively bound the HCGS conditions; therefore, the limited cases where the HCGS separation has not been met in the installation are justified. The two reports referenced have been submitted under separate cover, by letter from R. L. Mittl, PSE&G, to A. Schwencer, NRC, dated August 30, 1984.

Based on the results of this test and analysis program, separation criteria for Class 1E conduit has been established which assures that 1) any failure or occurrence in a Class 1E conduit will not degrade a redundant essential Class 1E circuit in adjacent Class 1E conduits, 2) a failure or occurrence in a non-Class 1E conduit will not degrade redundant essential Class 1E circuits in adjacent Class 1E conduits.

The criteria established are as follows:

a. Circuits carrying control, instrumentation, or power cable (where the power cable is limited to 480 volt or lower and No. 12 AWG or smaller) are allowed to touch each other.

b. Conduit carrying essential Class 1E 4.15 kV power cables or 480 volt load center power cables will have a one inch minimum separation from conduits carrying Class 1E circuits of a redundant channel.

c. Conduit carrying non-essential 13.8 kV, 4.16 kV, or 480 volt load center cables that bridge conduits carrying essential Class 1E circuits of redundant channels will be separated from conduit carrying circuits of the redundant channel to give a minimum separation of one inch.

d. Conduit carrying essential Class 1E power cable of 480 volt or lower voltage with conductor size larger than number 12 AWG, and not covered by b. above, will meet the following criteria:

   1. Will have a minimum of 1/8-inch separation from the surface of any conduit crossing above which contains an essential Class 1E circuit of the redundant channel.

2. Are allowed to touch conduits containing an essential Class 1E circuit of the redundant channel when installed in horizontal, side by side configuration.

3. Will have a minimum separation of one inch from conduits containing an essential Class 1E circuit of the redundant channel mounted directly above and running parallel.

e. Conduit carrying non-essential power cable of 480 volt or lower voltage with conductor size larger than number 12 AWG, and not covered by 3. above, that bridge conduits carrying essential Class 1E circuits of redundant channels will be treated as in d.1,2 and 3 for proper separation from the redundant channel.

2. Non-Class 1E conduit separation from Class 1E tray.

In safety-related areas of the plant there are non-Class 1E rigid steel conduits within one inch of Class 1E tray. The non-Class 1E conduit contains only control, instrumentation or power cables. HCGS performed a series of tests to demonstrate the adequacy of the rigid steel conduit as an effective barrier for protection of cables in open tray from faulted cables within the rigid steel conduit. The test results are documented on Wyle Test Report No. 17730-01 which has been submitted to the NRC as discussed in Section 8.1.4.14.3.1. The tests showed that a rigid steel conduit containing a faulted cable of one 500 kcmil or three No. 2/0 AWG cables and separated by 1/2 inch from an open tray acted as an effective barrier.

Based on the tests, the following configurations are considered acceptable:

a. Rigid steel conduit containing non-Class 1E cables no larger than 500 kcmil with service voltage no higher than 480 V ac and separated a minimum of 1 inch from an open tray containing Class 1E control and instrumentation cables.

b. The minimum separation distance of 1 inch, measured either from the top or bottom of the tray surface to the conduit surface, may be reduced to 1/2 inch provided that the size of the cable in the conduit is no larger than No. 2/0 AWG.

c. In cases that are not within the boundary of Items a and b above, a cable tray cover will be provided.

3. Metal clad cable separation from Class 1E raceways.

Metal clad cables, type MC, are used in non-Class 1E circuits only. The minimum separation between the metal clad cable and Class 1E raceways (open top trays or conduits) is one inch. The type MC cable is a factory assembly of one or more conductors each individually insulated, covered with an overall insulating jacket and all enclosed in a metallic sheath of interlocking galvanized steel. The cable has passed the vertical flame test of IEEE 383-1974.

HCGS performed tests on the separation configuration of metal clad cable to open top tray. The test results are documented on the same Wyle test report described in Paragraph 2 above. One test showed that a faulted No. 2 AWG metal-clad cable can cause a cable in the open top tray to exceed its qualified temperature for approximately 2 minutes while the temperature of other cables within the tray remained within acceptable limits during the fault condition. A repeat test was performed with successful results. A minimum of 3/4-inch separation distance between the metal clad cable and tray surfaces was used in tests.

Based on the tests, the following separation criteria are considered acceptable:

a. A non-Class 1E metal clad cable shall be separated by a minimum of 6 inches from Class 1E open tray surface, top or bottom. The largest metal clad cable shall be No. 2 AWG.

b. If the criterion of Paragraph a cannot be met, then a tray cover will be installed, or the metal clad cable will be wrapped with Siltemp material. The installation of the tray cover or Siltemp shall be sufficient to prevent any possible contract between the surfaces of the metal-clad cable and cables in the tray.

4. Armor clad and antenna cables' separation from Class 1E trays.

Armor clad cables are used in non-Class 1E circuits only. This type of cable is a factory assembly of insulated conductors enclosed in a metallic sheath formed from interlocking galvanized steel strip. Use of this cable is limited to lighting system applications. The antenna cables for the UHF radio system are non-Class 1E. These cables, designated by tradenames of Heliax and Radiax, are constructed of a flame retardant jacket over a copper-corrugated strip which encloses the dielectric and center conductor.

HCGS performed a series of tests to demonstrate the adequacy of the separation distance between these cables and an open tray. The test results are documented on the same Wyle Test Report described in Paragraph 2 above. The tests showed that a faulted armor clad or Heliax cable separated by 1 inch from an open tray did not impact the cables in the tray.

Based on the tests, the following separation criteria are considered acceptable.

a. Non-Class 1E armor clad cable with maximum conductor size of No. 10 AWG shall have a minimum separation of 1 inch from an open tray containing Class 1E control and instrumentation cables.

b. Non-Class 1E UHF radio system antenna cables (Heliax and Radiax shall have the same separation as in Paragraph a above.

5. Free air cable drop separation.

Certain cable installations require that a cable enter or leave from a cable tray or enclosure without enclosing the cable in a conduit. The cable is considered as a free-air cable (unsupported) and it may be exposed to other Class 1E cables or conduits.

HCGS performed a series of tests to demonstrate the adequacy of separation configurations that are representative of the free air cable installations. The test results are documented on the same Wyle Test Report described in Paragraph 2. above. The tests showed that the following configurations are acceptable:

a. A free air power cable of No. 2/0 AWG and separated by 1 inch from a rigid steel conduit containing instrumentation cable of No. 16 AWG size.

b. A free air instrumentation cable of No. 16 AWG and separated by 1 inch from a rigid steel conduit containing a power cable of No. 2/0 AWG size.

c. A free air control cable of No. 14 AWG size separated by a minimum of 1 inch from a power cable of 500 kcmil size which is wrapped with Siltemp material.

d. Siltemp material is an acceptable separation barrier.

The above testing represented worst case generic configurations and established minimum separation distances. Specific configurations are reviewed for conformance with the limits established by the tests. In cases where the free air cable installation does not conform with the above, the free air cable will be wrapped with Siltemp material or enclosed in conduit until the minimum separation distance of 1 inch is met.

6. Neutron Monitoring System cables under reactor pressure vessel.

Due to spatial limitation beneath the reactor pressure vessel and the need for movement of Neutron Monitoring System (NMS) detectors and control rod drive (CRD) position indicators during plant operation, the separation requirement defined in Section 8.1.4.14 for NMS channels cannot be met in this area. Specifically, the conduits for redundant NMS cables do not enclose the entire cable lengths from the pedestal wall to the cable end connectors and less than 1 inch separation between conduits is necessary to allow for proper routing, distribution, and connection of cables to the NMS detectors. The less than 1 inch separation between conduits is considered acceptable per the analysis described in Paragraph 1. above because NMS cables are for instrumentation. In addition, the NMS and CRD systems are powered from non-Class 1E sources. Therefore, failure or faults on these cables do not impact Class 1E power sources. A single failure analysis for the neutron monitoring and process radiation monitoring systems, dated August 1984, was submitted to the NRC by letter dated September 9, 1984, R. L. Mittl, PSE&G, to A. Schwencer, NRC.

The above analysis identified the cases on a generic level. The installation and inspection of raceways are ongoing and the specific cases where the analysis applies are documented on nonconformance reports that are part of the Nuclear Oversight Quality Verification Inspection program.

B. Position C.1, section 3.8, requires an “isolation device” be used to separate class 1-E and non-class 1-E equipment. Revision 2 of this regulatory guide supplements this requirement by stating, “interrupting devices actuated only by a fault current are not considered to be isolation devices”. Justification to attach test equipment to “associated” circuitry of an OPERABLE emergency diesel during periodic monthly and 24 hour run surveillance testing, is documented in evaluation H2001-003. A failure modes effect analysis of all connection points to the control circuitry provides assurance that diesel operability is not compromised.

Position C.12 states that redundant cable spreading areas should be provided. HCGS has only a single cable spreading area.

Position C.12 endorses IEEE 384-1974, Paragraph 5.1.3, which indicates that in cable spreading areas the minimum separation distance between redundant Class 1E cable trays should be 1 foot between trays separated horizontally and 3 feet between trays separated vertically. The separation criteria used on HCGS for cable spreading areas is a minimum of 1 foot horizontal distance and 18 inch vertical distance between redundant Class 1E cable trays. See Section 8.1.4.14.3.1 for justification of this vertical separation distance.

Position C.15 specifies that redundant Class 1E batteries be located in separate safety class structures and be served by independent ventilation systems. The 250 V Class 1E batteries for electrical divisions A and B, located on Elevation 163 feet of the Auxiliary Building, are served by a common ventilation exhaust system that has redundant exhaust fans but not independent ductwork. See Section 8.1.4 for further discussion of electrical separation and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.76 Conformance to Regulatory Guide 1.76, Revision 0, April 1974: Design Basis Tornado for Nuclear Power Plants

HCGS complies with Regulatory Guide 1.76.

For further details on protection of HCGS against tornadoes, see Sections 2.3.1.2 and 3.3.2.

1.8.1.77 Conformance to Regulatory Guide 1.77, Revision 0, May 1974: Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors

Regulatory Guide 1.77 is not applicable to HCGS.

1.8.1.78 Conformance to Regulatory Guide 1.78, Revision 0, June 1974: Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The HCGS design meets the requirements of Regulatory Guide 1.78. Postulated accidents regarding hazardous chemicals stored at the HCGS and SGS, and frequently shipped past the site were evaluated. It was concluded that the HCGS control room will remain habitable during a release of any of the evaluated hazardous chemicals. From the control room habitability evaluations, the only chemical stored and/or delivered onsite that can accumulate to any appreciable concentration in the control room is ammonium hydroxide. Calculations simulating the release of ammonium hydroxide at the SGS indicated that the control room operators have more than two (2) minutes from the time of detection of ammonia to the toxicity limit listed in Table C-1 of Regulatory Guide 1.78 to take corrective actions.

The HCGS utilizes the detection mechanism (human detection) as allowed by Regulatory Position C.7. Instrumentation is not provided to detect hazardous chemicals entering the control room and alarm control room personnel.

1.8.1.79 Conformance to Regulatory Guide 1.79, Revision 1, September 1975: Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

Regulatory Guide 1.79 is not applicable to HCGS.

1.8.1.80 Conformance to Regulatory Guide 1.80, Revision 0, June 1974: Preoperational Testing of Instrument Air Systems

Regulatory Guide 1.80 was superseded by Regulatory Guide 1.68.3 on April 20, 1982. See Section 1.8.1.68.3 for discussion of conformance to Regulatory Guide 1.68.3.

1.8.1.81 Conformance to Regulatory Guide 1.81, Revision 1, January 1975: Shared Emergency and Shutdown Electric Systems for Multiunit Nuclear Power Plant

Regulatory Guide 1.81 is not applicable to HCGS.

1.8.1.82 Conformance to Regulatory Guide 1.82, Revision 0, June 1974: Sumps for Emergency Core Cooling and Containment Spray Systems

Regulatory Guide 1.82 is not applicable to HCGS because it is applicable only to PWRs where Reactor Building sumps are designed to be a source of water for emergency core cooling.

1.8.1.83 <u>Conformance to Regulatory Guide 1.83, Revision 1, July 1975: Inservice Inspection of Pressurized Water Reactor Steam Generators Tubes</u>

Regulatory Guide 1.83 is not applicable to HCGS.

1.8.1.84 <u>Conformance to Regulatory Guide 1.84, Revision 24, June 1986: Design and Fabrication Code Case Acceptability, ASME Section III Division 1</u>

HCGS complies with Regulatory Guide 1.84, with the following exception.

Position C.1 states that the use of ASME Code Case N-252 is acceptable provided that the PSAR and/or FSAR indicate the capacitive discharge welding application, the material, and the material thickness. This information has not been provided for all applications, because Code Case N-252 contains sufficient controls, i.e., maximum power output, welding procedure specification preparation, and minimum material thickness, to prevent surface cracking or other adverse conditions. Information on the use of Code Case N-252 on the reactor coolant pressure boundary is presented below. Code Case N-252 was invoked in the fabrication of nuclear service piping. The guidance in Code Case N-252 was applied to the attachment of thermocouples to materials for the monitoring of metal temperature during post-weld heat treatment. The material involved was carbon steel (ASME P No. 1) greater than 1-1/2-inch thick.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.85 Conformance to Regulatory Guide 1.85, Revision 18, August 1981: Materials Code Case Acceptability ASME Section III Division 1

HCGS complies with Regulatory Guide 1.85, with the following exception:

Position C.1 of Revision 17 of Regulatory Guide 1.85 accepted the use of Code Case N-242. Its use was acceptable, provided that the PSAR and/or FSAR identify all components and supports requiring the use of Paragraphs 1.0 through 4.0 of the ASME Code Case. A listing of components and supports in all applications is not provided because Code Case N-242 contains sufficient controls to ensure the proper certification of materials. A list of all reactor coolant pressure boundary components that invoked Code Case N-242 in ASME Section III, Class 1 applications is provided in Table 1.8-3.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.86 Conformance to Regulatory Guide 1.86, Revision 0, June 1974: Termination of Operating Licenses for Nuclear Reactors

HCGS complies with the intent of Regulatory Guide 1.86.

1.8.1.87 Conformance to Regulatory Guide 1.87, Revision 1, June 1975: Guidance for Construction of Class 1 Components in Elevated Temperature Reactors (Supplement to ASME Section III Code Cases 1592, 1593, 1594, 1595, and 1596)

Regulatory Guide 1.87 is not applicable to HCGS.

1.8.1.88 Conformance to Regulatory Guide 1.88, Revision 2, October 1976: Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records

NRC Regulatory Guide 1.88 was withdrawn by the NRC on July 31, 1991. HCGS is committed to the requirements of NQA-1-1994, Supplement 17S-1, Section 4, Storage, Preservation, and Safekeeping, with the following specific exceptions for the Records Storage Room No. 145 in the Nuclear Administration Building:

1. Per NUGEG-0800, Records Storage Room No. 145 was built to comply with option (3) "a 2 hour rated fire resistant file room meeting NFPA 232…". Regulatory Guide 1.88 endorses NFPA 232-1975 and NQA-1-1994 endorses NFPA 232-1986; however, during construction, NFPA 232-1991 was utilized to provide an acceptable level of record protection,

2. A cable tray which passes through the room is enclosed with a three hour rated symmetrical wrap system to assure its presence will not affect the room's content or fire protection features, and

3. The ceiling is pierced by several miscellaneous drainage lines and two ventilation ducts. A drip pan, with discharge outside the room, is provided for the miscellaneous drainage plumbing to minimize the potential for inadvertent wetting of records and fire dampers are installed in the ventilation ducts.

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1.8.1.89 Conformance to Regulatory Guide 1.89, Revision 0, November 1974: Qualification of Class 1E Equipment for Nuclear Power Plants

HCGS will attempt to comply with Regulatory Guide 1.89 on a case by case basis.

See Section 3.11 for further discussion of environmental qualification and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.90 Conformance to Regulatory Guide 1.90, Revision 1, August 1977: Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons

Regulatory Guide 1.90 is not applicable to HCGS because HCGS does not have a concrete containment.

1.8.1.91 Conformance to Regulatory Guide 1.91, Revision 1, February 1978: Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants

Regulatory Guide 1.91 is not applicable to HCGS.

1.8.1.92 Conformance to Regulatory Guide 1.92, Revision 1, February 1976: Combining Modal Responses and Spatial Components in Seismic Response Analysis

Although Regulatory Guide 1.92 is not applicable to HCGS, per its implementation section, HCGS complies with it.

Some of the equipment supplied under the NSSS contract has had to be reassessed according to the provisions of Regulatory Guide 1.92. Equipment that does not qualify under these provisions has been identified in the Hope Creek Seismic Qualification Review Program and qualified by more sophisticated analyses or testing.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.93 Conformance to Regulatory Guide 1.93, Revision 0, December 1974: Availability of Electric Power Sources

Although Regulatory Guide 1.93 is not applicable to HCGS, per its implementation section, HCGS complies with it. See Chapter 16 for further discussion.

1.8.1.94 Conformance to Regulatory Guide 1.94, Revision 1, April 1976: Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

Although Regulatory Guide 1.94 is not applicable to HCGS, HCGS complies with NQA-1-1994 and the intent of the regulatory guide, with the following exceptions and clarifications:

1. In-Process Tests on Concrete.

   Sampling is as follows:

   a. Sampling point - Compressive strength test cylinders are cast from representative samples taken from the discharge of the batch plant stationary mixer. Slump and temperature of the concrete are recorded when cylinders are being cast. Air content is also recorded when the mix design contains air entraining admixture.

   b. Correlation - For purpose of correlation between the stationary mixer and the transport discharge, cylinders are also cast from a sample taken at the transport discharge of the same batch from which a sample was taken at the stationary mixer, until correlation is established. For pumped concrete, this sample is taken at the pump line discharge.

   c. Sampling for compressive strength tests from the pump discharge - It is not practical to take compressive strength test samples at the pump discharge because it is sometimes 200-feet high or deep in the structures.

d. Samples for correlation are not taken when water has been added to the truck at point of discharge.

2. Mechanical (Cadweld) Splice Testing - HCGS compliance is discussed in Section 1.8.1.10.

3. A list of tests to which the project has taken exceptions, is as follows:

   a. Aggregate moisture content testing per ASTM C566. The project specification requires aggregate moisture content testing but with no reference to a specific test procedure.

      This test is used by the concrete supplier to determine the amount of water to be added to the concrete batch weights to produce the proper slump. Other test methods for moisture are equally acceptable to determine the proper amount of water.

   b. ASTM C142, friable particles, is required only initially by the project. ASTM C123, lightweight pieces, and C235, soft fragments, are not required. Project requirements are adequate since the aggregate is crushed rock, subject to very little change.

   c. Aggregate - Flat and elongated particle measurement is fully described in the project specification, but without a reference to CRD-C119. The description provides an adequate method in lieu of CRD-C119.

   d. Water and ice - Setting time is determined by ASTM C266, Gillmore needles, instead of ASTM C191,

e. Water and ice - autoclave expansion, for soundness. This test is not required by the project, but other tests required by Specification C191, Section 6.2, for chlorides and sulfates should provide an indication of any long term reduction of strength.

f. Admixtures - an infrared spectrophotometry analysis for the chemical composition on a composite of each shipment. This test is not a specification requirement. However, HCGS does require the manufacturer to furnish certifications for every shipment stating that the materials originally approved have not been changed.

See Section 3.8.6 for further discussion.

1.8.1.95 Conformance to Regulatory Guide 1.95, Revision 1, January 1977: Protection of Nuclear Power Plant Control Room Operators Against An Accidental Chlorine Release

Regulatory Guide 1.95 is not applicable to HCGS, per its implementation section.

Furthermore, there is no need to include special provisions for chlorine detection at the control room ventilation intakes since chlorine is not stored onsite or at the nearby SNGS. At HCGS, sodium hypochlorite is used for water chlorination purposes.

In any case, the control room ventilation system is provided with manual isolation capability, and self-contained breathing masks are provided for the main control room operators.

For further discussion of chemical releases and main control room habitability, see Section 1.8.1.78.

1.8.1.96 Conformance to Regulatory Guide 1.96, Revision 1, June 1976: Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants

(Historical Information)

HCGS complies with Regulatory Guide 1.96.

In response to Generic Issue C-8, “MSIV Leakage and Leakage Control System Failure”, 10CFR50.67, and Regulatory Guide 1.183, the MSIV leakage control system was removed.

1.8.1.97 Conformance to Regulatory Guide 1.97, Revision 2, December 1980: Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

1.8.1.97.1 General Position Statement

HCGS concurs with the intent of Regulatory Guide 1.97, Revision 2. The intent of the regulatory guide is to ensure that necessary and sufficient instrumentation exists at each nuclear power station for assessing plant and environmental conditions during and following an accident, as required by 10CFR Part 50, Appendix A and General Design Criteria 13, 19, and 64. Regulatory Guide 1.97 requirements are being implemented except in those instances in which differences from the letter of the guide are justified technically and then they can be implemented without disrupting the general intent of the regulatory guide, or other applicable design criteria.

In assessing Regulatory Guide 1.97, HCGS has drawn upon information contained in several applicable documents, such as ANS 4.5, NUREG/CR-2100, and the BWROG Emergency Procedures Guidelines, and on data derived from other analyses and studies. HCGS has attempted to meet the intent of, as opposed to the literal compliance with the provisions of the regulatory guide, because of their specific nature. In general, HCGS intends to follow the criteria used by the NRC for establishing Category 1, 2, and 3 instruments. Where differences between the Regulatory Guide Categories exist, justification for the category chosen is provided. This approach is preferable as some Regulatory Guide 1.97 requirements call for excessive ranges or categories or both, others call for functions already available, and still others could adversely affect operator judgment under certain conditions. For example, research by S. Levy, Inc., (SLI), show that core thermocouples will provide conflicting information to BWR operators. HCGS intends to follow the criteria used by the NRC for establishing Category 1, 2, and 3 instruments.

The following HCGS compliance statement is applicable to the regulatory positions defined in Regulatory Guide 1.97, Revision 2 (the paragraph numbers cited correspond to those in Regulatory Guide 1.97).

1. Accident Monitoring Instrumentation

Par. 1.1: HCGS concurs with this definition.

Par. 1.2: HCGS concurs with this definition.

Par. 1.3: Instruments used for accident monitoring to meet the provisions of Regulatory Guide 1.97 will have the proper sensitivity, range, transient response, and accuracy to ensure that both during and following a design basis accident the control room operator is able to perform his role in bringing the plant to, and maintaining it in, a safe shutdown condition and in assessing actual or possible releases of radioactive material.

Accident monitoring instruments that are required to be environmentally qualified will be qualified as described in Section 3.11. The seismic qualification of instruments is described in Section 3.10.

The HCGS quality assurance program ensures that accident monitoring instruments comply with the applicable requirements of Title 10CFR50, Appendix B. Table 3.2-1 identifies where these requirements have been applied.

The HCGS program for periodic checking, testing, calibrating, and calibration verification of accident-monitoring instrument channels (Regulatory Guide 1.118) is identified in Section 16, "Technical Specifications."

Par. 1.3.1 A third channel of instrumentation for Category 1 instruments will be provided only if:

a. a failure of one accident monitoring channel results in information ambiguity that would lead operators to defeat or fail to accomplish a required safety function, and

b. if one of the following measures cannot provide the information:

   1. Cross-checking with an independent channel that monitors a different variable bearing a known relationship to the variable being monitored.

   2. Providing the operator with the capability of perturbing the measured variable to determine which channel has failed by observing the response on each instrument.

   3. Using portable instrumentation for validation. Category 1 instrument channels, which are designated as being part of a Class 1E system, will meet the more stringent design requirements of either the system or the Regulatory Guide.

The requirements for physical independence of electrical systems (Regulatory Guide 1.75) are identified in Section 1.8.1.75.

Par. 1.3.2: HCGS concurs with the regulatory position for Category 2 instrumentation, except as modified by Par. 1.3 above.

Par. 1.3.3: HCGS concurs with the regulatory position for Category 3 instrumentation.

Par. 1.4: Instruments designated as Categories 1 and 2 for variable types A, B, and C should be identified in such a manner as to optimize the human factors engineering and presentation of information to the control room operator. This position is taken to clarify the intent of Regulatory Guide 1.97, which specified that these instruments be easily discerned for use during accident conditions (see Issue 1 Section 1.8.1.97.4)

Par. 1.5: HCGS concurs with the regulatory position taken in this section, except as modified by Par. 1.3 above.

Par. 1.6: It is the position of HCGS that in terms of accident monitoring at HCGS, Table 1 of Regulatory Guide 1.97 is not representative of the optimum SPT of variables required and does not necessarily represent correct variable ranges or instrumentation categories.

HCGS accident monitoring variables are identified in Table 7.5-1. The classification of instrumentation used to measure the variables as Category 1, 2, or 3 is Regulatory Guide 1.97. However, differences between the Regulatory Guide Categories and HCGS categories for each variable described in Table 1 of Regulatory Guide 1.97 is described in Section 1.8.1.97.3.

The HCGS position on the implementation of each variable described in Table 1 of Regulatory Guide 1.97 is presented in Section 1.8.1.97.3.

2. Systems Operation Monitoring and Effluent Release Monitoring Instrumentation

   The HCGS position stated in Par. 1.3 above is applicable to the Type D and E variables described in Regulatory Guide 1.97.

   Par. 2.1: HCGS concurs with these definitions.

   Par. 2.2: HCGS concurs with these regulatory position.

   Par. 2.3: HCGS concurs with these regulatory position

   Par. 2.4: HCGS concurs with these regulatory position.

   Par. 2.5: The HCGS position as stated in Par. 1.6 above is applicable to this regulatory position.

1.8.1.97.2 Proposed Type A Variables

Regulatory Guide 1.97, Revision 2, designates all Type A variables as Category 1 plant specific, thereby defining none in particular. The regulatory guide defines Type A variables as:

> Those variables to be monitored that provide primary information required to permit the control room 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 design basis accident events.

Regulatory Guide 1.97 defines primary information as "information that is essential for the direct accomplishment of the specified safety functions." Variables associated with contingency actions that may be identified in written procedures are excluded from this definition of primary information.

HCGS has determined that the monitoring of the following noted safety functions for the listed operator actions are required to meet the intent of Regulatory Guide 1.97. The specific Type A variables are identified in Section 1.8.1.97.3.1:

Variable A1. Deleted

Variable A2. RPV Pressure

Safety Function: 1) Core cooling; 2) maintain reactor coolant system integrity.

Operator action: 1) Depressurize RPV and maintain safe cooldown rate by any of several systems, such as main turbine bypass valves, HPCI, RCIC, and RWCU: 2) manually open one SRV to reduce pressure to below SRV setpoint if an SRV is cycling.

Variable A3. RPV Water Level

Safety Function: Core cooling.

Operator action: Restore and maintain RPV water level.

Variable A4. Suppression Pool Water Temperature

Safety Function: 1) Maintain containment integrity and 2) maintain reactor coolant system integrity.

Operator action: 1) Operate available suppression pool cooling system when pool temperature exceeds normal operating limits; 2) scram reactor if temperature reaches limit for scram; 3) if suppression pool temperature cannot be maintained below the heat capacity temperature limit, maintain RPV pressure below the corresponding limit; and 4) close any stuck open relief valve.

Variable A5. Suppression Pool Water Level

Safety Function: 1) maintain containment integrity.

Operator action: Maintain suppression pool water level within normal operating limits: 1) transfer RCIC suction from the condensate storage tank (CST) to the suppression pool in the event of high suppression pool level; and 2) if suppression pool water level cannot be maintained below the suppression pool load limit, maintain RPV pressure below corresponding limit.

Variable A6. Drywell Pressure

Safety Function: 1) maintain containment integrity and 2) maintain reactor coolant system integrity.

Operator action: Control primary containment pressure by any of several systems, such as containment atmosphere control systems, suppression pool sprays, drywell sprays, etc.

1.8.1.97.3 Plant Variables For Accident Monitoring

In brief, the measurement of the following five variable types provides the noted required information to plant operators during and after an accident: 1) Type A-primary information, on the basis of which operators take planned specified manually controlled actions; 2) Type B-information about the accomplishment of plant safety functions; 3) Type C-information about the breaching of barriers to fission product release; 4) Type D-information about the operation of individual safety systems; and 5) Type E-information about the magnitude of the release of radioactive materials.

The three categories (1,2,3) of required variables define the design and qualification criteria for the instrumentation that is to be used for their measurement. Category 1 imposes the most stringent requirements; Categories 2 and 3 impose progressively less stringent requirements.

The categories are also related (per Regulatory Guide 1.97) to "key variables." Key variables are defined differently for the different variable types. For Type B and Type C variables, the key variables are those variables that most differently indicate the accomplishment of a safety function; instrumentation for these key variables is designated Category 1. Key variables that are Type D variables are defined as those variables that most directly indicate the operation of a safety function; instrumentation for these key variables is usually Category 2. And key variables that are Type E variables are defined as those variables that most directly indicate the release of radioactive material; instrumentation for these key variables is also usually Category 2. Backup variables for Type B, C, D and E variables are generally Category 3. A complete discussion of the variable types and instrumentation design criteria is presented in Regulatory Guide 1.97.

HCGS positions on the implementation of the variables listed in Table 1 of Regulatory Guide 1.97 and on the assignment of design and qualification criteria for the instrumentation proposed for their measurement is summarized in the tabulation that follows.

The variables are listed here in the same sequence used in Table 1, Regulatory Guide 1.97; however, for convenience in cross-referencing entries and supporting data, the variables are designated by letter and number. For example, the sixth B-type variable listed in Regulatory Guide 1.97 is denoted here as variable B6.

The HCGS variable category designated ("HC") and the Regulatory Guide 1.97 category designated ("RG") are shown for each variable and for its instrumentation design criteria and category. In general, there are three positions cited by HCGS: 1) the variable and required instrumentation was implemented in accordance with the regulatory position stated in Table 1, Regulatory Guide 1.97 2) was implemented with qualifying exceptions or revisions; and 3) was not implemented.

As necessary, the HCGS positions are justified or substantiated by the 11 "Issues" (identified in the tabulation of variables where applicable) noted in Section 1.8.1.97.4.

1.8.1.97.3.1 Type A variables (Reference Section 1.8.1.97.2)

A1. Deleted

A2. Reactor pressure (HC Category 1, RG Category 1) Position: Implemented.

A3. Coolant level in reactor (HC Category 1, RG Category 1) Position: Implemented. See B4.

A4. Suppression pool water temperature (HC Category 1, RG Category 1) Position: Implemented. See D6.

A5. Suppression pool water level (HC Category 1, RG Category 1) Position: Implemented. See C7 and D5.

A6. Drywell pressure (HC Category 1, RG Category 1) Position: Implemented. See B7, B9, C8, C10, and D4.

1.8.1.97.3.2 Type B Variables

1. Reactivity Control

B1. Neutron Flux (RG Category 1) Position: Not implemented. See issue 2, Section 1.8.1.97.4.2.

B2. Control Rod Position (HC Category 3, RG Category 3) Position: Implemented.

B3. RCS Soluble Boron Concentration (sample) (HC Category 3, RG Category 3) Position: Implemented.

2. Core Cooling

B4. Coolant Level in Reactor (HC Category 1, RG Category 1) Position: Implemented. See A3.

B5. BWR Core Thermocouples (RG Category 1) Position: Not implemented. See B4, C3, and SLI-8121 (December, 1981) (Appendix A to Reference 1.8-4).

3. Maintaining Reactor Coolant System Integrity

B6. RCS Pressure (HC Category 1; RG Category 1) Position: Implemented. See A2, C4, C9, and Issue 3, Section 1.8.1.97.4.3.

B7. Drywell Pressure (HC Category 1; RG Category 1) Position: Implemented. See A6, B9, C8, C10, and D4.

B8. Drywell Sump Level (HC Category 3; RG Category 1) Position: Implemented as Category 3. See C6 and Issue 4, Section 1.8.1.97.4.4.

4. Maintaining Containment Integrity

B9. Primary Containment Pressure (HC Category 1; RG Category 1)Position: Implemented. See A6, B7, C8, C10, and D4.

B10. Primary Containment Isolation Valve Position (excluding check valves) (HC Category 1; RG Category 1)
Position: Implemented (See Section 6.2.4.2). Redundant indication is not required on each redundant isolation valve.

1.8.1.97.3.3 Type C Variables

1. Fuel Cladding

C1. Radioactivity Concentration or Radiation Level in Circulating Primary Coolant (RG Category 1) Position: Not implemented. See Issue 5, Section 1.8.1.97.4.5.

C2. Analysis of Primary Coolant (gamma spectrum) (HC Category 3; RG Category 3) Position: Implemented

C3. BWR Core Thermocouples (RG Category 1) Position: Not implemented. See B4, B5, and SLI-8121 (December, 1981) (Appendix A to Reference a.8-4).

2. Reactor Coolant Pressure Boundary

C4. RCS Pressure (HC Category 1; RG Category 1)
Position: Implemented. See A2, B6, and C9.

C5. Primary Containment Area Radiation (HC Category 1; RG Category 3)
Position: Implemented as Category 1. See E1.

C6. Drywell Drain Sumps Level (identified and unidentified leakage) (HC Category 3; RG Category 1)
Position: Implemented as Category 3. See B8 and Issue 4, Section 1.8.1.97.4.4.

C7. Suppression Pool Water Level (HC Category 1; RG Category 1)
Position: Implemented. See A5 and D5.

C8. Drywell Pressure (HC Category 1; RG Category 1)
Position: Implemented. See A6, B7, and B9, C10, and D4.

3. Containment

C9. RCS Pressure (HC Category 1; RG Category 1)
Position: Implemented. See A2, B6, and C4.

C10. Primary Containment Pressure (HC Category 1; RG Category 1)
Position: Implemented. See A6, B7, B9, C8, and D4.

C11. Containment and Drywell H_2 Concentration (HC Category 3; RG Category 1)
Position: Implemented as Category 3 in accordance with License Amendment 160.

C12. Containment and Drywell Oxygen Concentration (HC Category 2; RG Category 1) Position: Implemented as Category 2 in accordance with License Amendment 160.

C13. Containment Effluent Radioactivity-Noble Gases (from identified release points including Filtration, Recirculation & Ventilation System Vent) (HC Category 3; RG Category 3) Position: Implemented.

C14. Radiation Exposure Rate (inside buildings or areas, e.g., Auxiliary Building, Reactor Building, which are in direct contact with primary containment where penetrations and hatches are located) (RG Category 2) Position: Not implemented. See E2, E3, and Issue 6, Section 1.8.1.97.4.6.

C15. Effluent Radioactivity-Noble Gases (from buildings as indicated above (HC Category 2; RG Category 2) Position: Implemented.

1.8.1.97.3.4 Type D Variables

1. Condensate and Feedwater System

D1. Main Feedwater Flow (HC Category 3; RG Category 3) Position: Implemented.

D2. Condensate Storage Tank Level (HC Category 3; RG Category 3) Position: Implemented.

2. Primary Containment Related System

D3. Suppression Chamber Spray Flow (HC Category 2; RG Category 2) Position: Implemented.

D4. Drywell Pressure (HC Category 2; RG Category 2) Position: Implemented.

D5. Suppression Pool Water Level (HC Category 2; RG Category 2) Position: Implemented. See A5 and C7.

D6. Suppression Pool Water Temperature (HC Category 1; RG Category 2) Position: Implemented, but must be Category 1. Both local and bulk temperature. See A4.

D7. Drywell Atmosphere Temperature (HC Category 2; RG Category 2) Position: Implemented.

D8. Drywell Spray Flow (HC Category 2; RG Category 2) Position: Implemented.

3. Main Steam System

(Historical Information)

D9. Main Steamline Isolation Valves' Leakage Control System Pressure (HC Category 2; RG Category 2)
Position: Implemented. (System is identified as Main Steam Isolation Valve Sealing System at HCGS).

D10. Primary System Safety Relief Valve Position, Including ADS or Flow Through or Pressure in Valve Lines (HC Category 2; RG Category 2)
Position: Implemented.

4. Safety Systems

D11. Isolation Condenser System Shell Side Water Level
Position: Not applicable to HCGS.

D12. Isolation Condenser System Valve Position
Position: Not applicable to HCGS.

D13. RCIC Flow (HC Category 2; RG Category 2)
Position: Implemented. See Issue 7, Section 1.8.1.97.4.7.

D14. HPCI Flow (HC Category 2; RG Category 2)
Position: Implemented. See Issue 7, Section 1.8.1.97.4.7.

D15. Core Spray System Flow (HC Category 2; RG Category 2)
Position: Implemented. See Issue 7, Section 1.8.1.97.4.7.

D16. LPCI System Flow (HC Category 2; RG Category 2)
Position: Implemented. See Issue 7, Section 1.8.1.97.4.7.

D17. SLC System Flow (HC Category 3; RG Category 2)
Position: Implemented as Category 3. See Issue 7, Section 1.8.1.97.4.7.

D18. SLC System Storage Tank Level (HC Category 2; RG Category 2)
Position: Implemented.

5. Residual Heat Removal (RHR) Systems

D19. RHR System Flow (HC Category 2; RG Category 2)
Position: Implemented.

D20. RHR Heat Exchange Outlet Temperature (HC Category 2; RG Category 2) Position: Implemented.

6. Cooling Water System

D21. Cooling Water Temperature to ESF System Components (HC Category 2; RG Category 2) Position: Interpreted as Safety Auxiliaries Cooling System (SACS) temperature and implemented.

D22. Cooling Water Flow to ESF System Components (HC Category 2; RG Category 2) Position: Interpreted as SACS flow and implemented.

7. Radwaste Systems

D23. High Radioactivity Liquid Tank Level (HC Category 3; RG Category 3) Position: Implemented.

8. Ventilation Systems

D24. Emergency Ventilation Damper Position (HC Category 2; RG Category 3) Position: Interpreted as meaning dampers actuated under accident conditions and whose failure could result in radioactive discharge to the environment. Control room damper position is indicated. Implemented.

9. Power Supplies

D25. Status of Standby Power and Other Energy Sources Important to Safety (hydraulic, pneumatic) (HC Category 2; RG Category 2) Position: Implemented; onsite sources only.

(Note: HCGS has implemented the following D-type variables as recommended by the BWROG; see Issue 8, Section 1.8.1.97.4.8.)

D26. Turbine Bypass Valve Position (HC Category 3) Position: Implemented. See Issue 8, Section 1.8.1.97.4.8.

D27. Condenser Hotwell Level (HC Category 3) Position: Implemented. See Issue 8, Section 1.8.1.97.4.8.

D28. Condenser Vacuum (HC Category 3) Position: Implemented. See Issue 8, Section 1.8.1.97.4.8.

D29. Condenser Cooling Water Flow (HC Category 3) Position: Interpreted as cooling water T across the condenser and implemented. See Issue 8, Section 1.8.1.97.4.8.

D30. Primary Loop Recirculation (HC Category 3) Position: Implemented. See Issue 8, Section 1.8.1.97.4.8.

1.8.1.97.3.5 Type E Variables

1. Containment Radiation

E1. Primary Containment Area Radiation-High Range (HC Category 1; RG Category 1) Position: Implemented in accordance with NUREG-0737 commitment. See C5.

E2. Reactor Building or Secondary Containment Area Radiation (RC Category 2 for Mark I and II containments)

Position: Not implemented for HCGS (Mark I) containment. See C14, E3, and Issue 9, Section 1.8.1.97.4.9.

2. Area Radiation

E3. Radiation Exposure Rate (inside buildings or areas where access is required to service equipment important to safety (HC Category 3; RG Category 2) Position: Implemented as Category 3, using existing instrumentation. See C14, E2, and Issue 10, Section 1.8.1.97.4.10.

3. Airborne Radioactive Materials Released From Plant

E4. Noble Gases and Vent Flow Rate (HC Category 2; RG Category 2) Position: Implemented.

E5. Particulates and Halogens (HC Category 3; RG Category 3) Position: Implemented.

4. Environs Radiation and Radioactivity

E6. Radiation Exposure Meters (continuous indication at fixed locations) Position: Deleted. See NRC errata of July 1981.

E7. Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability (HC Category 3; RG Category 3) Position: Implemented.

E8. Plant Environs Radiation (portable instrumentation) (HC Category 3; RG Category 3) Position: Implemented (portable equipment).

E9. Plant and Environs Radioactivity (portable instrumentation) (HC Category 3; RG Category 3) Position: Implemented (portable equipment).

5. Meteorology

E10. Wind Direction (HC Category 3; RG Category 3) Position: Implemented.

E11. Wind Speed (HC Category 3; RG Category 3) Position: Implemented.

E12. Estimation of Atmospheric Stability (HC Category 3; RG Category 3) Position: Implemented.

6. Accident-Sampling Capability (Analysis Capability Onsite)

E13. Primary Coolant and Sump (HC Category 3-Primary Coolant only; RG Category 3) Position: Implemented Primary Coolant. (Dissolved hydrogen or Total Gas not implemented). Sump not implemented. See Issue 11, Section 1.8.1.97.4.11.

E14. Containment Air (HC Category 3; RG Category 3) Position: Implemented.

The instrumentation for monitoring and display of type A, B, C, D, and E variables at HCGS is identified on Table 7.5-1.

1.8.1.97.4 Supplementary Analyses

These supplementary analyses support positions cited in Section 1.8.1.97.1 (Issue 1) and Section 1.8.1.97.3 (Issues 2-12).

1.8.1.97.4.1 Issue 1 - Instrument Identification

Regulatory Guide 1.97 specifies, in paragraph 1.4.b, the following: "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."

The objective of this regulatory position is the achievement of good human factors engineering in the presentation of information to the control room a operator. This objective is best achieved by evaluating current practices and procedures that provide for identifying instruments in a manner that aids the operator; redundant labels would tend to distract the operator and cause confusion.

Instruments designated as Categories 1 and 2 for monitoring variable types A, B, and C should be identified in such a manner as to optimize applicable human factors engineering and presentation of information to the control room operator. This position is taken to clarify the intent of Regulatory Guide 1.97, which specifies that these instruments be easily discerned for use during accident conditions. The method of identification used at HCGS will be based on the results of a human factors analysis performed on the HCGS main control room (See Section 18).

1.8.1.97.4.2 Issue 2 - Variable B1

The measurement of neutron flux is specified as the key variable in monitoring the status of reactivity. Neutron flux is classified as a Type B variable, Category 1.

Hope Creek is committed to NEDO-31558-A which was approved by the NRC by a safety evaluation dated January 13, 1993 to exempt currently designed BWRs from RG 1.97 Category 1 requirements for the Neutron Monitoring System. NEDO-31558-A provides alternate criteria for range, accuracy, response characteristics, equipment qualification, function time, seismic qualification, redundancy and separation, power sources, channel availability, quality assurance, display and recording, equipment identification, interfaces, service test and calibration, human factors, and direct measurement. NEDO-31588-A requirements are met therefore neutron monitoring is not implemented as a RG 1.97 required variable.

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1.8.1.97.4.3 Issue 3 - Trend Recording

The purpose of addressing Issue 3 is to determine which variables set forth in Regulatory Guide 1.97 require trend recording.

Regulatory Guide 1.97, paragraph 1.3.2f, states the general requirement for trend recording as follows: "Where direct and immediate trend or transient information is essential for operator information or action, the recording should be continuously available for dedicated recorders." Using the BWROG Emergency Procedures Guidelines (EPG's) as a basis, the only trended variables required for operator action are reactor water level and reactor vessel pressure.

Other variables at HCGS are recorded as identified on Table 7.5-1.

1.8.1.97.4.4 Issue 4 - Variables B8 and C6

Regulatory Guide 1.97 requires Category 1 instrumentation to monitor drywell sump level (variable B8) and drywell drain sumps level (variable C6). These designations refer to the drywell equipment and floor drain tank levels. Category 1 instrumentation indicates that the variable being monitored is a key variable. In Regulatory Guide 1.97, a key variable is defined as "... that single variable (or minimum number of variables) that most directly indicates the accomplishment of a safety function..." The following discussion supports the HCGS safety position that drywell sump level and drywell drain-sumps levels should be designated as Category 3 instrumentation requirements.

The HCGS drywell has two drain sumps. One drain is the equipment drain sump, which collects identified leakage; the other is the floor drain sump, which collects unidentified leakage.

Although the level of the drain sumps can be a direct indication of breach of the Rector Coolant System pressure boundary, the indication is not unambiguous, because that can be water in those sumps during normal operation. There is other instrumentation required by Regulatory Guide 1.97 that would indicate leakage in the drywell:

1. Drywell pressure-variable B7, Category 1

2. Drywell temperature-variable D7, Category 2

3. Primary containment area radiation-variable C5, Category 1

The drywell sump levels signal neither automatic protection control circuitry nor the operator to take safety-related actions. Both sumps have level detectors that provide only the following nonsafety indications:

1. Continuous level indication

2. Rate of rise indication

3. High level alarm (starts first sump pump)

4. High-high level alarm (starts second sump pump)

Regulatory Guide 1.97 requires instrumentation to function during and after an accident. The drywell sump systems are deliberately isolated at the primary containment penetration upon receipt of an accident signal to establish containment integrity. This fact renders the drywell sump level signal irrelevant. Therefore, by design, drywell level instrumentation serves no useful accident monitoring function.

The Emergency Procedure Guidelines use the RPV level and the drywell pressure as entry conditions for the Level Control Guideline. A small line break will cause the drywell pressure to increase before a noticeable increase in the sump level. Therefore, the drywell sumps will provide a "lagging" versus "early" indication of a leak.

Based on the above considerations, HCGS believes that the drywell sump level and drywell drain sump level instrumentation should be designated as Category 3, "high-quality off the shelf instrumentation."

1.8.1.97.4.5 Issue 5 - Variable C1

Regulatory Guide 1.97 specifies that the status of the fuel cladding be monitored during and after an accident. The specified variable to accomplish this monitoring is variable C1-radioactivity concentration or radiation level in circulating primary coolant. The range is given as "1/2 Tech. Spec. Limit to 100 times Tech. Spec. Limit, R/hr." In Table 1 of Regulatory Guide 1.97, instrumentation for measuring variable C1 is designated as Category 1. The purpose for monitoring this variable is given as detection of breach," referring, in this case, to breach of fuel cladding.

The usefulness of the information obtained by monitoring variable C1, in terms of helping the operator in his efforts to prevent and mitigate accidents, has not been substantiated. The particular planned operator action to be taken based on monitoring this variable is not specified in the current draft of the Emergency Procedure Guidelines (EPGs). The critical actions that must be taken to prevent and mitigate a gross breach of fuel cladding are 1) shut down the reactor and 2) maintain water level. Monitoring variable C1, as directed in Regulatory Guide 1.97, will have no influence on either of these actions. The purpose of this monitor falls in the category of "information that the barriers to release of radioactive material are being challenged" and "identification of degraded conditions and their magnitude, so the operator can take actions that are available to mitigation the consequences." Additional operator actions to mitigate the consequences of fuel barriers being challenged, other than those based on Type A and B variables, have not been identified.

Regulatory Guide 1.97 specifies measurement of the radioactivity of the circulating primary coolant as the key variable in monitoring fuel cladding status during isolation of the NSSS. The words "circulating primary coolant" are interpreted to mean coolant, or a representative sample of such coolant, that flows past the core. A basic criterion for a valid measurement of the specified variable is that the coolant being monitored is coolant that is in active contact with the fuel, that is, flowing past the failed fuel. Monitoring the active coolant (or a sample thereof) is the dominant consideration. The Process Sampling System provides a representative sample which can be monitored.

The subject of concern in the Regulatory Guide 1.97 requirement is assumed to be an isolated NSSS that is shutdown. This assumption is justified as current monitors in the condenser off-gas and main steam lines provide reliable and accurate information on the status of fuel cladding when the plant is not isolated. Further, the Process Sampling System will provide an accurate status of coolant radioactivity, and hence cladding status, following an accident. In the interim between NSSS isolation and sampling, monitoring of the primary containment radiation and containment hydrogen will provide information on the status of the fuel cladding.

Later in the sequence, the sample can be augmented by area radiation monitor when the RHR system is being used to remove core decay heat.

The designation of instrumentation for measuring variable C1 should be Category 3, because no planned operator actions are identified and no operator actions are anticipated based on this variable serving as the key variable. Existing Category 3 instrumentation is adequate for monitoring fuel cladding status.

1.8.1.97.4.6 Issue 6 - Variable C14

Variable C14 is defined in Table 1 of Regulatory 1.97 as follows: "Radiation exposure rate (inside buildings or areas, e.g., Auxiliary Building, Fuel Handling Building, Secondary Containment), which are in direct contact with primary containment where penetrations and hatches are located." The reason for monitoring variable C14 is given as "Indication of breach."

The use of local radiation exposure rate monitors to detect breach or leakage through primary containment penetrations is impractical and unnecessary. In general, radiation exposure rate in the Reactor Building will be largely a function of radioactivity in primary containment and in the fluids flowing in ECCS piping, which will cause direct radiation shine on the area monitors. Also, because of the amount of piping and the number of electrical penetrations and hatches and their widely scattered locations, local radiation exposure rate monitors could give ambiguous indications. The proper way to detect breach of containment is by using the plant noble gas effluent monitors.

Therefore, it is the position of HCGS that this parameter not be implemented.

1.8.1.97.4.7 Issue 7 - Variables D13-D17

Regulatory Guide 1.97 specifies flow measurements of the following systems: reactor core isolation cooling (RCIC) (variable D13), high pressure coolant injection (HPCI) (variable D14, core spray (variable D15), low pressure coolant injection (LPCI) (variable D16), and standby liquid control (SLC) (variable D17). The purpose is for monitoring the operation of individual safety systems. Instrumentation for measuring these variables is designated as Category 2; the range is specified as 0 to 110 percent of design flow. These variables are related to flow into the reactor pressure vessel (RPV).

The RCIC, HPCI, and core spray systems each have one branch line; the test line downstream of the flow measuring element. The test line is provided with a motor operated valve that is normally closed HPCI and RCIC also share a motor operated valve that is normally open). Further, the valve in the test line automatically closes when the emergency system is actuated, thereby ensuring that indicated flow is not being diverted by the test line. Proper valve position can be verified by a direct indication of valve position on the main control board.

Although the LPCI has several branch lines located downstream of each flow measuring element, upon initiation of the LPCI, the valves in the system automatically line up for proper operation and prevent flow diversion by branch lines. Proper valve position can be verified by the operator using main control board indication of valve position.

For all of the above systems, there are valid primary indicators other than flow measurement to verify the performance of the emergency system; for example, reactor vessel water level.

Flow measuring devices are not provided for the SLC system. The pump discharge header pressure, which is indicated in the control room, will indicated SLC pump operation. Besides the discharge header pressure observation, the operator can verify the proper functioning of the SLC system by monitoring the following:

1. The decrease in the level of the SLC storage tank,

2. The boron injection induced reactivity change in the reactor as measured by neutron flux.

3. The main control room motor status indicating lights (or motor current),

4. Squib valve continuity indicating lights.

The use of these indications is believed to be a valid alternative to SLC system flow indication.

The flow measurement schemes for the RCIC, HPCI, core spray, and LPCI meet the Category 2 requirements of Regulatory Guide 1.97.

Monitoring the SLC system can be adequately done by measuring the above named Category 3 variables rather than the actual flow.

1.8.1.97.4.8 Issue 8 - Variables D26-D30

Regulatory Guide 1.97 states that "The plant designer should select variables and information display channels required by his design to enable the control room personnel to ascertain the operating status of each individual safety system and other systems important to safety to that extend necessary to determine if each system is operating or can be placed in operation..." The purpose of this analysis was to determine whether certain other D-type variables should be added to Table 1, Regulatory Guide 1.97.

Regulatory Guide 1.97 addressed safety systems and systems important to safety to mitigate consequences of an accident. Another list of variables has been compiled for the BWR in NUREG/CR-2100 (Boiling Water Reactor Status Monitoring during Accident Conditions, April 1981). That report and a companion report, NUREG/CR-1440 (Light Water Reactor Status Monitoring during Accident Conditions, June 1980), address plant systems not important to safety, as well as systems that are important to safety. In particular, these reports consider the potential role of the turbine generator system in mitigating certain accidents. These two reports were reviewed in determining whether the listed variables (D26-D30) should be added to the Regulatory Guide 1.97 list.

The NUREG evaluations used a systematic approach to derive a variables list. The basic approach of the analysis was to focus on those accident conditions under which the operator is most likely to be confronted with "and/or" accident conditions which result in the most serious consequences should the operator fail to accomplish his required tasks. This is a probabilistic event tree type of study, and the reports used the sequences of the Reactor Safety Study (WASH 1400), and similar studies. The events in each sequence that involved operator action were identified; also, events were added to the event tree to include additional operator actions that could mitigate the accident. The event tree defines a series of key plant states that could evolve as the accident progresses and as the operator attempts to respond. Thus the operator's informational needs are linked to these plant states.

NUREG/CR-2100 is a BWR evaluation undertaken to address appropriate operator actions, the information needed to take those actions, and the instrumentation necessary and sufficient to provide the required information.

The sequences evaluated were:

1. Anticipated transient followed by loss of decay heat removal.

2. Anticipated transients without scram (ATWS).

3. Anticipated transient together with failure of HPCI, RCIC, and low pressure ECCS.

4. Large loss of coolant accident (LOCA) with failure of emergency core cooling systems.

5. Small LOCA with failure of emergency core cooling systems.

The Regulatory Guide 1.97 list is based on accidents that result in an isolated NSSS. The NUREG documents considered accidents that could be prevented or mitigated by using water inventory and the heat sink in the turbine plant.

Five of the 15 variables identified in the NUREG, but not in Regulatory Guide 1.97, are recommended as Type D, Category 3 additions to the Regulatory Guide 1.97 list. Four of these variables are in the turbine plant: the turbine bypass valve position, condenser hotwell level, condenser vacuum, and condenser cooling water flow. These variables provide a primary measure of the status of a heat sink or water inventory in the turbine plant. The turbine-plant systems are not to be classed as "safety systems" or as systems important to safety. The addition of reactor primary loop recirculation as a variable is also recommended.

HCGS has implemented these four variables plus reactor primary loop recirculation (Variable D26-D30) as plant specific Category 3 items in accordance with Regulatory Guide 1.97 considerations.

Note that HCGS has implemented variable D29 (condenser cooling water flow) by monitoring the circulating water temperature rise across the condenser as a positive T across the condenser coupled with no decrease in condenser vacuum is an adequate indication of condenser cooling water flow.

1.8.1.97.4.9 Issue 9 - Variable E2

Regulatory Guide 1.97 specifies that "Reactor building or secondary containment area radiation" (variable E2) should be monitored over the range of 10^{-1} to 10^{4} R/hr for Mark I and II containments, and over the range of 1 to 10^{7} R/hr for Mark III containments. The classification for Hope Creek is Category 2; for Mark III, the classification is Category 1.

As discussed in the variable C14 position statement (Issue 6), Reactor Building area radiation is an inappropriate parameter to use to detect or assess primary containment leakage.

The Reactor Building exhaust and refueling floor area exhaust are continuously monitored by their respective Radiation Monitoring System as described in Sections 11.5.2.1.3 and 11.5.2.1.2. Any concentration of airborne radioactivity in excess of preset limits as detected by either of these systems (possibly indicating a leak from the primary containment) will initiate the Filtration, Recirculation and Ventilation System vent (FRVSV) and will also provide signals to the Primary Containment Isolation System to initiate primary containment isolation to the extent described in Section 7.3.1.1.5.

The Reactor Building exhaust and refueling floor area exhaust are normally routed to the south plant vent Radiation Monitoring System as described in Section 11.5.2.2.2. The south plant vent radiation monitoring system instrumentation ranges and sensitivities are listed in Table 11.5-1.

If the FRVSV system is initiated (either manually or automatically by the Reactor Building exhaust or refueling floor area exhaust radiation monitoring systems) the Reactor Building exhaust and refueling floor area exhausts are automatically shifted to the FRVSV system. The FRVSV effluent air is monitored by the FRVSV radiation monitoring system as described in Section 11.5.2.2.3. The FRVSV radiation monitoring system instrumentation ranges and minimum sensitivities are listed in Table 11.5-1.

It is the Hope Creek position that the monitoring functions performed by the south plant vent radiation monitoring system and the FRVSV radiation monitoring system with the ranges and sensitivities listed in Table 11.5-1 provide a much more reliable means of detection of significant releases, release assessment, and long term surveillance than could be provided by reactor building area radiation monitors.

Therefore, it is the position of HCGS that the specified Reactor Building area radiation monitors are not required for HCGS.

1.8.1.97.4.10 Issue 10 - Variable E3

Regulatory Guide 1.97 specifies in Table 1, variable E3, 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/hr for detection of significant releases, for release assessment, and for long-term surveillance.

In general, access is not required to any area of the Reactor Building in order to service safety-related equipment in a post-accident situation. 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 Reactor Building atmosphere. The existing lower range (typically 3 decades lower than the Regulatory Guide 1.97 range) area radiation monitors would be used only in those instances in which anticipated radiation levels were within measurable instrument ranges.

It is HCGS's position that this parameter was modified to allow credit for existing area radiation monitors. That is, this parameter should be reclassified as Category 3 with the ranges specified on Table 11.5-1.

1.8.1.97.4.11 Issue 11 - Variable E13

Regulatory Guide 1.97 requires installation of the capability for obtaining grab samples (variable E13) of the containment sumps and the reactor building sumps for the purpose of release assessment, verification, and analysis.

The need for sampling a particular sump must take into account its location and the design of the plant in which it is installed. For all accidents in which radioactive material would be in the HCGS drywell sumps, these sumps will be isolated and will overflow to the suppression pool. A suppression pool sample can therefore be used as a valid alternative to a drywell sump sample.

The analysis of Reactor Building sumps liquid samples can be used for release assessment, as suggested in Regulatory Guide 1.97, only for those designs in which potentially radioactive water can be pumped out of a controlled area to an area such as radwaste. For designs in which sump pump out is not allowed on a high radiation or a LOCA signal, or in which the water is pumped to the suppression pool, a sump sample does not contribute to release assessment. The use of the subject sump samples for verification and analysis is of little value; a sample of the suppression pool and reactor water, as required by other portions of Regulatory Guide 1.97, provides a much better measurement for these purposes. The guidelines recommended by the BWR Owners' Group and GE shall be followed in lieu of Total Dissolved Gas Group and GE shall be followed in lieu of Total Dissolved Gas Analysis. This was agreed to in a meeting between NRC management (R. Vollmer) and GE (F. Quick) dated December 12, 1983.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.97.5 Exceptions to Regulatory Guide 1.97

1.8.1.97.5.1 Neutron Flux

Regulatory Guide 1.97 recommends Category 1 instrumentation with a range of from 10^{-6} to 100 percent of full power. HCGS has provided three redundant sets of instrumentation having overlapping ranges which, together, cover the recommended range. However, the instrumentation is Category 2. The source-range monitors and intermediate-range monitors are driven into the core soon after shutdown and this makes it highly probable that one or more of the existing detectors will be inserted. The operator can actuate the standby liquid control system on loss of instrumentation. There are four source-range monitors, eight intermediate-range monitors, six average power range monitors and individual local power range monitors.

This deviation is similar to most boiling water reactors.

1.8.1.97.5.2 Drywell Sump Level and Drywell Drains Sump Level

HCGS is supplying instrumentation for this variable that is Category 3 rather than the recommended Category 1. Justification for this deviation is as follows:

1. The sump level is not an unambiguous indication of a breach in the reactor coolant system pressure boundary

2. Other instrumentation (drywell pressure, drywell temperature and primary containment radiation) indicates leakage in the drywell

3. The sump level does not cause any automatic initiation of safety-related systems or alert the operator to take any safety-related actions

4. The sump level provides only non-safety indications

5. The sumps are deliberately isolated at the primary containment penetration upon receipt of an accident signal. This is done to establish containment integrity.

The instrumentation supplied will provide appropriate monitoring for the parameters of concern. This is based on 1) for small leaks, the instrumentation is not expected to experience harsh environments during operation, 2) for larger leaks, the sumps fill promptly and the sump drain lines isolate due to the increase in drywell pressure, thus negating the drywell sump level and drywell drain sumps level instrumentation, 3) the drywell pressure and temperature as well as the primary containment area radiation instrumentation can be used to detect leakage in the drywell, and 4) this instrumentation neither automatically initiates nor alerts the operator to initiate operation of a safety-related system in a post-accident situation.

1.8.1.97.5.3 Radiation Level in Circulating Primary Coolant

The process sampling system provides a means of obtaining samples of reactor coolant and determining the status of fuel cladding. The radiation monitors in the condenser off-gas and the main steamlines provide information on the status of fuel cladding when the plant is not isolated. Monitoring the primary containment radiation and containment hydrogen concentration provide this information when the plant is isolated.

1.8.1.97.5.4 Radiation Exposure Rate

Regulatory Guide 1.97, Revision 2, specifies instrumentation for this Type C variable. HCGS's position is that this variable need not be implemented. Revision 3 of Regulatory Guide 1.97 (Reference 7) states that exposure rate monitors inside buildings for detecting containment breach were deleted from the guide.

Regulatory Guide 1.97, Revision 2, specifies instrumentation for this Type E variable. The stated range for this Category 2 instrumentation is 10^{-1} to 10^{4} R/hr. HCGS's position is that no access to a harsh environment area to service safety-related equipment following an accident is required; and that long-term accessibility will be evaluated with portable radiation survey instruments and containment atmosphere sampling and analysis. HCGS has provided Category 3 instrumentation for this variable with a range of 0.1 mR/hr to 10^{4} R/hr, which will be used only where the anticipated radiation levels are within the instrument range.

Regulatory Guide 1.97, Revision 2, specifies Category 3 instrumentation for this variable. This instrumentation will be used only where they are expected to remain on scale following an accident.

1.8.1.97.5.5 Emergency Core Cooling Flow

HCGS has deviated from the recommendations of Regulatory Guide 1.97 for measuring the flow of the following systems:

a. Reactor Core Isolation Cooling (RCIC)

b. High Pressure Coolant Injection (HPCI)

c. Core Spray (CS)

d. Low Pressure Coolant Injection (LPCI)

Regulatory Guide 1.97 recommends Category 2 instrumentation for these variables, each with a range of 0 to 110 percent of design flow.

As a deviation, a potential for flow diversion for each of the four systems exists. This diversion could be caused by open valves in branch lines downstream of the flow measuring elements. The instrumentation for measuring the flow for these systems is adequate since it meets the intent of the Regulatory Guide and because the valve position is known and the valves close automatically on an accident signal.

The flow instrumentation for the HPCI measures to 107 percent of design flow (6,000 gallons per minute). The existing range is adequate to provide the necessary accident and post-accident information. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

1.8.1.97.5.6 Standby Liquid Control System Flow

Regulatory Guide 1.97 specifies Category 2 instrumentation with a range of 0 to 110 percent of design flow for this variable. HCGS does not measure this variable directly. The pump discharge header pressure will indicate pump operation to the operator. Other parameters that can be monitored to verify system operation include: level decrease in the boric acid storage tank, neutron flux, pump motor contactor position (or running current), and squib valve continuity indication. These parameters are sufficient to establish that there is flow in the standby liquid control system.

Positive displacement pumps are used for the standby liquid control system. High pump pressure indicates flow blockage and erratic or low pressure indicates a line break. The above indications are valid for an alternate standby liquid control system flow indication.

1.8.1.97.5.7 Cooling Water Temperature to Engineered Safety Features (ESF) System Components

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from 40 to 200°F. HCGS provides this instrumentation for the safety auxiliary cooling system, with a range from 32 to 95°F (UFSAR, Table 7.5-1).

Table 9.2-3 of the UFSAR lists the design water outlet temperature minimum at 32°F, the maximum at 95°F. This corresponds to the range of the instrumentation supplied. Therefore, the supplied range is acceptable.

1.8.1.97.5.8 Reactor Building or Secondary Containment Radiation

Regulatory Guide 1.97 recommends that this variable be monitored with Category 2 instrumentation; HCGS's position is that secondary containment area radiation is not an appropriate parameter to use for assessing primary containment leakage or detecting significant releases.

The use of local radiation exposure rate monitors to detect breach or leakage through primary containment penetrations results in ambiguous indications. This is due to the radioactivity in the primary containment, the radioactivity in the fluids flowing in emergency core coolant system piping and the amount and location of fluid and electrical penetrations. The use of the plant noble gas effluent monitors is the proper way to accomplish the purpose of this variable.

The alternate instrumentation for this variable is provided by the Category 2 filtration, recirculation and ventilation system vent radiation monitoring system. It has a range of 10^{-6} to 10 μCi/cc beta and 5 to 10^{5} μCi/cc gamma. This measures the radiation levels in the exhausts from the reactor building and refueling floor area in the post-accident situation. Normal monitoring of the exhausts from these areas is done by the south plant vent radiation monitoring system. This is also a Category 2 system that includes normal and extended ranges.

1.8.1.97.5.9 Accident Sampling (Primary Coolant Containment Air and Sump)

Regulatory Guide 1.97 recommends sampling and onsite analysis capability for the reactor coolant system, contaminant sump, ECCS pump room sumps and other similar auxiliary building sump liquids, the containment sump and containment air. HCGS's post-accident sampling facility provides sampling and analysis. However, there are deviations from the following recommendations.

1. The sumps are not sampled

2. Dissolved hydrogen or total gas analysis capability is not included.

HCGS takes exception to Regulatory Guide 1.97 with respect to post accident sampling capability. This exception is discussed in Section 1.10 under NUREG-0737, Item II.B.3.

1.8.1.98 Conformance to Regulatory Guide 1.98, Revision 0, March 1976: Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Off-gas System Failure in a Boiling Water Reactor

HCGS complies with Branch Technical Position ETSB 11-5, Revision 0, July 1981, in lieu of Regulatory Guide 1.18.

For further discussion, see Section 15.7.1.

1.8.1.99 Conformance to Regulatory Guide 1.99, Revision 2, May 1988: Radiation Embrittlement of Reactor Vessel Materials

Regulatory Guide 1.99 is not applicable.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.100 Conformance to Regulatory Guide 1.100, Revision 1, August 1977: Seismic Qualification of Electric Equipment For Nuclear Power Plants

Although Regulatory Guide 1.100 is not applicable to HCGS, per its implementation section, HCGS complies with it.

See Section 3.10 for further discussion of seismic qualification of electrical components and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.101 Conformance to Regulatory Guide 1.101, Revision 3, August 1992: Emergency Planning and Preparedness for Nuclear Power Reactors

Hope Creek conforms to Regulatory Guide 1.101, Revision 3, August 1992, and uses as the planning basis "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants", NUREG-0654/FEMA-REP-1, Rev.1 (November 1980), and "Methodology for Development of Emergency Action Levels", NUMARC/NESP-007.

The Emergency Plan Manuals, as revised, describe the total emergency program as described in Section 13.3.

1.8.1.102 Conformance to Regulatory Guide 1.102, Revision 1, September 1976: Flood Protection for Nuclear Power Plants

HCGS complies with Regulatory Guide 1.102.

1.8.1.103 Conformance to Regulatory Guide 1.103, Revision 1, October 1976: Post-Tensioned Prestressing Systems for Concrete Reactor Vessels and Containments

Regulatory Guide 1.103 was withdrawn on July 21, 1981. It is not applicable to HCGS.

1.8.1.104 Conformance to Regulatory Guide 1.104, Revision 0, February 1976: Overhead Crane Handling Systems for Nuclear Power Plants

Regulatory Guide 1.104 was withdrawn on August 22, 1979.

Nevertheless, the HCGS reactor building polar crane was designed and procured using Regulatory Guide 1.104 as a guide; except as noted below. The current criteria for evaluating single failure proof crane design is NUREG-0554. The HCGS design complies with NUREG-0554, except as noted in Section 9.1.5. For a comparison of the HCGS design to NUREG-0554, see Section 9.1.5.

HCGS complies with Regulatory Guide 1.104 with the exceptions and clarifications noted below, which are keyed to the Regulatory Guide paragraph numbers.

Position 1 - Performance Specification and Design Criteria

a. The crane may be used for miscellaneous construction lifts, including assembly of reactor internals. Construction lifts will be within the rated crane capacity, and therefore a separate performance specification was not prepared. Otherwise, the design complies.

b.1. This paragraph is not applicable because the crane is not located inside containment. The crane girders are sealed. Venting is not required because the crane is designed for reactor building pressure differentials.

b.2. Structural members essential to structural integrity that are not redundant have been impact tested. It is expected that the 60°F margin will be satisfied for HCGS service conditions. However, this margin is considered excessive as a general rule.

b.3. Cold proof testing is not required because impact testing in accordance with b.2. was performed.

b.4. Low alloy steel is not used in the crane.

c. The design complies.

d. The design complies.

e. A fatigue analysis is not considered necessary in view of the low number of load cycles to be experienced.

f. Welding procedures comply. No low alloy steel is used.

Position 2 - Safety Features

a. The design complies.

b. The design complies.

c. The design complies.

d. The design complies.

Position 3 - Equipment Selection

a. The design complies.

b. Not applicable to the crane design.

c. The design complies.

d. The design complies.

e. The design complies.

f. The design complies.

g. A 200 percent static test of the hook was performed, followed by nondestructive examination. Breaking strength tests were performed on samples of the hoisting rope. The assembled crane will be statically tested at 125 percent of the rated load prior to initial use in accordance with OSHA.

h. The design complies.

i. The design complies.

j. Provision is made in design to prevent the occurrence of two-blocking. Redundant upper limit switches of diverse design are provided to interrupt hoisting power.

k. Provisions are made to capture the drum in the event its shaft or bearings fail. Movement of the drum in this event will be limited mechanically so that the gear trains and holding brakes will not disengage. Total failure of the drum itself is not considered credible. Stresses are low. Impact testing in accordance with Paragraph 1.b.2) was performed on the drum material.

l. The design complies.

m. The design complies. It is interpreted that installation of two holding brakes is a sufficient design provision to protect against single failure.

n. The design complies.

o. Stepless controls are provided for hoisting. Plugging protection is provided to the extent that torque and current will be limited if the operator moves the master controller in the opposite direction in order to obtain a rapid reversal.

p. The design complies.

q. The design complies.

r. The design complies.

s. The value of the maximum working load (MWL) is undefined. However, if the MWL is assumed to be a 125-ton cask lift, that is 83 percent of the design rating of 150 tons.

Position 4 - Mechanical Check, Testing, and Preventive Maintenance

a. Testing will comply.

b. A two-block test will not be performed other than to check that the hoisting limit switches are functional. A test for load hangup may be performed, but without the provision for one revolution of the drum before the start of hoisting.

c. The crane will be marked with the design rated load.

d. This paragraph is not applicable because impact testing was performed on materials that met the ASME criteria for materials requiring impact testing.

Position 5 - Quality Assurance

The quality assurance program of 10CFR50, Appendix B is applied to the crane. Therefore, it complies.

1.8.1.105 Conformance to Regulatory Guide 1.105, Revision 1, November 1976: Instrument Setpoints

Although Regulatory Guide 1.105 is not applicable to HCGS, per its implementation section, HCGS complies with it, subject to the following interpretation of Position C.5, which requires that instruments have a setpoint securing device. Position C.5 is invalid if it is demonstrated by analysis or test that such devices do not aid in maintaining the required setpoint.

It is evident from the licensee event reports (LER) that the vast majority of events attributed to drift are associated with mechanically actuated devices. To circumvent this problem, the HCGS project avoids the use of direct process connected electromechanical devices in safety-related systems. For safety-related circuits, HCGS uses proportional transmitting devices to make the primary measurement. The switching device or bistable is an electronic switch located in main or remote panels.

Because Regulatory Guide 1.105 does not differentiate between the types of bistable actuation (mechanical or electronic), HCGS requested suppliers to demonstrate by test, preferably during the tests performed to comply with IEEE 323, that their electronic switch is not subject to unacceptable drift.

Position C.5 also requires that securing devices be under administrative control. If securing devices are required, based upon test results, administrative control consists of control of access to areas within the plant where these devices are located.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.106 Conformance to Regulatory Guide 1.106, Revision 1, March 1977: Thermal Overload Protection for Electric Motors on Motor Operated Valves

Although Regulatory Guide 1.106 is not applicable to HCGS, HCGS implements this Regulatory Guide as discussed in Section 8.3.1.1.2.10.

See Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.107 Conformance to Regulatory Guide 1.107, Revision 1, February 1977: Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures

Regulatory Guide 1.107 is not applicable to HCGS.

1.8.1.108 Conformance to Regulatory Guide 1.108, Revision 1, August 1977: Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

HCGS complies with Regulatory Guide 1.108, with the following exception:

1. During the preoperational test phase, following the diesel 24-hour full load test, the proper design accident loading sequence will be demonstrated by the test described in Section 14.2.12.1.47. This test will verify the ability of the SDG to start and accept the sequenced design loads as specified in Table 8.3-1. This test will provide ECCS flows to the reactor vessel.

2. The criteria regarding sustained load levels of 100 percent and 110 percent can be demonstrated when those significant parameters being measured have stabilized to acceptable values. Although the 100 percent load level should be maintained for 22 hours followed by a 110 percent load level for 2 hours, reduced run times at 110 percent load levels are not regarded as an inadequate demonstration as defined by Position C.2.c provided: Runtime is sufficient to stabilize significant parameters being measured at the 110 percent load level and additional runtime (continuous beyond 22 hours) at the 100 percent load level is available to the diesel generator's load-carrying capability on an extended basis to compensate for the reduced runtime at the 110 percent load level.

3. For periodic testing required by the Hope Creek Technical Specifications, the test per this regulatory position will be performed during shutdown, except as noted in item 4. This test will simulate, separately, a loss of offsite power, and a loss of offsite power plus a LOCA condition, to verify the SDGs' ability to start and accept the sequence design loads.

4. For periodic testing required by the Hope Creek Technical Specifications, exception to regulatory position C.2.a.(5) is taken with respect to simulating a loss of offsite power (regulatory position C.2.a.(1)) and demonstrating the proper operation for design-accident-loading-sequence to design-load requirement

(regulatory position C.2.a.(2). Instead, the diesel generators will be subjected to a hot restart test (no loading required) that will follow either the 24-hour endurance run or a 2-hour loaded run of the diesel generator. Additionally, both the 24-hour endurance run and the for restart test may be performed during any mode of operation.

5. Regulatory Guide 1.108 criteria for determining and reporting valid tests and failures and accelerated diesel generator testing have been superceded by implementation of the Maintenance Rule for diesel generators per 10CFR50.65. This was approved in Hope Creek License Amendment 119.

6. Tests described in regulatory position C.2.a and C.2.b will be performed at a frequency determined under the Surveillance Frequency Control Program.

1.8.1.109 Conformance to Regulatory Guide 1.109, Revision 1, October 1977: Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10CFR Part 50, Appendix I

HCGS complies with Regulatory Guide 1.109.

For further discussion, see Section 15.

1.8.1.110 Conformance to Regulatory Guide 1.110, Revision 0, March 1976: Cost Benefit Analysis for Radwaste Systems For Light Water Cooled Nuclear Power Reactors

HCGS complies with Regulatory Guide 1.110.

1.8.1.111 Conformance to Regulatory Guide 1.111, Revision 1, July 1977: Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light Water Cooled Reactors

HCGS complies with Regulatory Guide 1.111.

See Chapter 15 for further discussion.

1.8.1.112 Conformance to Regulatory Guide 1.112, Revision 0-R, May 1977: Calculation of Release of Radioactive Materials in Gaseous and Liquid Effluent from Light Water Cooled Power Reactors

HCGS complies with Regulatory Guide 1.112.

1.8.1.113 Conformance to Regulatory Guide 1.113, Revision 1, April 1977: Estimating Aquatic Dispersion of Effluents From Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I

HCGS complies with Regulatory Guide 1.113.

See Chapter 15 for further discussion.

1.8.1.114 Conformance to Regulatory Guide 1.114, Revision 1, November 1976: Guidance on Being Operator at the Controls of a Nuclear Power Plant

HCGS is committed to Regulatory Guide 1.114. This Regulatory Guide will be incorporated in an operating department directive or the appropriate NBU administrative procedure(s).

1.8.1.115 Conformance to Regulatory Guide 1.115, Revision 1, July 1977: Protection Against Low Trajectory Turbine Missiles

HCGS complies with Regulatory Guide 1.115.

For further discussion of missile protection, see Section 3.5.

1.8.1.116 Conformance to Regulatory Guide 1.116, Revision 0-R, June 1976: Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems

HCGS complies with NQA-1-1994, and the intent of the regulatory position set forth in the Regulatory Guide.

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1.8.1.117 Conformance to Regulatory Guide 1.117, Revision 1, April 1978: Tornado Design Classification

Although Regulatory Guide 1.117 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion of tornado loadings, see Section 3.3.2.

1.8.1.118 Conformance to Regulatory Guide 1.118, Revision 2, June 1978: Period Testing of Electric Power and Protection Systems

Regulatory Guide 1.118 is not applicable to HCGS per its implementation section. However, with certain exceptions related to the use of temporary alterations during the performance of required at-power surveillance tests, HCGS is in compliance with this Regulatory Guide.

1.8.1.119 Conformance to Regulatory Guide 1.119, Revision 0, June 1976: Surveillance Program for New Fuel Assembly Designs

Regulatory Guide 1.119 was withdrawn by the NRC on June 23, 1977 and is not applicable.

1.8.1.120 Conformance to Regulatory Guide 1.120, Revision 1, November 1977: Fire Protection Guidelines for Nuclear Power Plants

HCGS complies with Regulatory Guide 1.120 with the exceptions discussed below. Since most of the guidelines in Regulatory Guide 1.120 have been incorporated in BTP CMEB 9.5.1, Revision 2, dated July 1981, the attached exceptions are only for those items that are not found in BTP CMEB 9.5.1, Revision 2. See Section 9.5.1 for an evaluation of SRP 9.5.1 and additional exceptions. Also, see Appendix 9A for an evaluation of the HCGS design against the requirements of 10CFR50, Appendix R.

Position C.4.a(10) of Regulatory Guide 1.120 requires that fire rated doors be normally closed and delay-alarmed with alarm and annunciation in the control room, and also locked closed or equipped with automatic self-closing devices using magnetic hold-open devices that are activated by smoke or rate-of-rise heat detectors protecting both sides of the opening.

At HCGS, all fire rated doors meet the requirements of Appendix R to 10 CFR 50 and BTP CMEB 9.5.1, Revision 2, to ensure that they will protect the door opening as required in case of fire. Fire doors are provided with mechanical closing devices. In addition, all fire doors will be kept closed and inspected daily to verify that they are in the closed position.

Position C.4.c.(4) of Regulatory Guide 1.120 requires that fire stops be installed every 20 feet along horizontal cable routing in areas that are not protected by automatic water systems. Vertical cable routings should have fire stops installed at each floor/ceiling level. Between levels or in vertical cable chases, fire stops should be installed at the midheight of the vertical run, 20 feet or more, but less than 30 feet or at 15 foot intervals in vertical runs of 30 feet or more, unless such vertical cable routings are protected by automatic water systems directed on the cable trays.

At HCGS, fire stops are not provided for horizontal or vertical cable routings in areas or cable chases that are not protected by automatic water systems. All cable and cable tray penetrations through fire rated barriers, e.g., walls, ceiling, or floors, are sealed to provide a fire resistance rating equal to the fire rating of the barrier. Cable chases are separated from each other by a

3-hour fire barrier. Only one channel is included in each chase, and access doors are provided at each floor elevation. All cable routings are accessible for manual firefighting, and the cable spreading room and control equipment mezzanine are provided with an automatic fire suppression system. In addition, an automatic fire detection system is provided in areas where redundant shutdown cable trains are located.

All cable routings meet the separation criteria for redundant shutdown trains as required in Appendix R to 10CFR50, and a fire in one fire area will not prevent safe shutdown of the plant. See Appendix 9A for comparison of HCGS to Appendix R.

Position C.4.d.(1) of Regulatory Guide 1.120 requires that to facilitate manual firefighting separate smoke and heat vents be provided in specific areas such as cable spreading rooms, diesel fuel oil storage areas, switchgear rooms, and other areas where potential for heavy smoke conditions exists.

At HCGS, automatic fire suppression systems are provided in areas where heavy smoke conditions may exist during a fire, i.e., cable spreading room and fuel oil storage areas. The cable spreading room is provided with a separate smoke removal system that serves the control area. For other areas of the plant, the normal ventilation system and portable smoke ejectors can be used to remove smoke generated during a fire. Automatic smoke detectors are provided in all fuel oil storage areas and electrical equipment rooms.

Position C.5.b.(5) of Regulatory Guide 1.120 requires that the fire water supply be calculated on the basis of the largest expected flow rate for a period of 2 hours, not less than 300,000 gallons. This flow rate should be conservatively based on 750 gpm for manual base streams plus the largest design demand of any sprinkler or deluge system as determined in accordance with NFPA 13 or NFPA 15. The fire water supply should be capable of delivering this design demand over the longest route of the water supply system.

At HCGS, the fire water supply meets the requirements of BTP CMEB 9.5.1, Revision 2, which specify that the fire water supply be based on a flow rate of 500 gpm for manual base streams plus the largest design demand of any sprinkler or deluge system.

Position C.6.j. of Regulatory Guide 1.120 requires that the diesel fuel oil tanks with a capacity greater than 1100 gallons not be located inside buildings containing safety-related equipment. If above ground tanks are used, they should be located at least 50 feet from any building containing safety-related equipment or, if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of 3 hours. Potential oil spills should be confined or directed away from buildings containing safety-related equipment. Totally buried tanks are acceptable outside or under buildings. See NFPA 30, Flammable and Combustible Liquid Code, for additional guidance.

At HCGS, the two 26,500 gallon diesel fuel oil storage tanks are located in each of the storage tank rooms at floor elevation 54 feet of the Auxiliary Building diesel generator area. There are four of these rooms containing a total of 212,000 gallons of fuel oil. Each room is enclosed by 3-hour fire barriers. The diesel area is separated from the control area by 3-hour fire walls. A manually actuated deluge sprinkler system, a fixed automatic carbon dioxide total flooding system, and an automatic fire detection system is provided for each room. The above diesel fuel oil storage meets the requirement of NFPA 30.

Although the combustible loading in the diesel fuel oil storage tank rooms is 7,045,000 Btu/ft^2 of floor area, oxygen depletion can restrict the fully developed period of any fire event to approximately 5 minutes in consideration of the postulated combustion of approximately 17.36 gallons of fuel oil.

HCGS's fuel oil storage conforms to the requirements of Appendix R to 10CFR50 and BTP CMEB 9.5.1, Revision 2.

1.8.1.121 Conformance to Regulatory Guide 1.121, Revision 0, August 1976: Bases for Plugging Degraded PWR Steam Generator Tubes

Regulatory Guide 1.121 is not applicable to HCGS.

1.8.1.122 Conformance to Regulatory Guide 1.122, Revision 1, February 1978: Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components

Although Regulatory Guide 1.122 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion of seismic design, see Sections 3.7 and 3.10.

1.8.1.123 Conformance of Regulatory Guide 1.123, Revision 1, July 1977: Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

NRC Regulatory Guide 1.123 was withdrawn by the NRC on July 31, 1991. HCGS complies with NQA-1-1994.

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1.8.1.124 Conformance To Regulatory Guide 1.124, Revision 1, January 1978: Service Limits and Loading Combinations for Class 1 Linear Type Component Supports

Although Regulatory Guide 1.124 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion, see Section 3.9.

1.8.1.125 Conformance to Regulatory Guide 1.125, Revision 1, October 1978: Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Although Regulatory Guide 1.125 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion of the Station Service Water System design, see Section 9.2.1.

1.8.1.126 Conformance to Regulatory Guide 1.126, Revision 1, March 1978: An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification

Regulatory Guide 1.126 is not applicable.

1.8.1.127 Conformance to Regulatory Guide 1.127, Revision 1, March 1978: Inspection of Water Control Structures Associated with Nuclear Power Plants

HCGS complies with Regulatory Guide 1.127 as applicable to the intake structure.

1.8.1.128 Conformance to Regulatory Guide 1.128, Revision 1, October 1978: Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants

Although Regulatory Guide 1.128 is not applicable to HCGS, per its implementation section, HCGS complies with it, subject to the clarification of Position C.1 that the ventilation exhaust duct is located just below the battery room ceiling in order to limit hydrogen concentrations to less than 2 percent by volume within the battery area.

For further discussion of the lead storage batteries, see Sections 8.1.4.22 and 8.3.2.

1.8.1.129 Conformance to Regulatory Guide 1.129, Revision 1, February 1978: Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants

Although Regulatory Guide 1.129 is not applicable to HCGS, per its implementation section, HCGS complies with it with the following exception.

Tests described in IEEE Std. 450-1975 will be performed at a frequency determined under the Surveillance Frequency Control Program.

For further discussion of the batteries see Section 8.3.2 and Section 16.

1.8.1.130 Conformance to Regulatory Guide 1.130, Revision 1, October 1978: Service Limits and Loading Combinations for Class 1 Plate and Shell Type Components Supports

Although Regulatory Guide 1.129 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion of design limits and loading combination, see Section 3.9.3.

1.8.1.131 Conformance to Regulatory Guide 1.131, Revision 0, August 1977: Qualification Tests of Electric Cables, Field Splices, and Connections for Light Water Cooled Nuclear Power Plants

Although Regulatory Guide 1.131 is not applicable to HCGS, per its implementation section, HCGS complies with it, with the following clarification:

Position C.5 states that the radiological source term and exposure rate simulating LOCA conditions should be obtained from Regulatory Guide 1.89 rather than from IEEE 323-1974. HCGS complies with this requirement. However, cable installed outside the reactor building is qualified to the relatively mild environment conditions that exist there.

1.8.1.132 Conformance to Regulatory Guide 1.132, Revision 1, March 1979: Site Investigations for Foundations of Nuclear Power Plants

Regulatory Guide 1.132 is not applicable to HCGS.

1.8.1.133 Conformance to Regulatory Guide 1.133, Revision 1, May 1981: Loose Part Detection Program for the Primary System of Light Water Cooled Reactors

Regulatory Guide 1.133 is no longer applicable to HCGS. The NRC has accepted General Electric (GE) Topical Report NEDC-32975P, "Regulatory Relaxation for BWR Loose Parts Monitoring Systems".

1.8.1.134 Conformance to Regulatory Guide 1.134, Revision 2, April 1987: Medical Evaluation of Licensed Personnel for Nuclear Power Plants.

HCGS complies with Regulatory Guide 1.34.

1.8.1.135 Conformance to Regulatory Guide 1.135, Revision 0, September 1977: Normal Water Level and Discharge at Nuclear Power Plants

Although Regulatory Guide 1.135 is not applicable to HCGS, per its implementation section, HCGS complies with it.

For further discussion, see Section 2.4.

1.8.1.136 Conformance to Regulatory Guide 1.136, Revision 2, June 1981: Materials, Construction, and Testing of Concrete Containments (Articles CC-1000, -2000, and -4000 through -6000 of the Code for Concrete Reactor Vessels and Containments)

Regulatory Guide 1.136 is not applicable to HCGS.

1.8.1.137 Conformance to Regulatory Guide 1.137, Revision 1, October 1979: Fuel-Oil Systems for Standby Diesel Generators

Although Regulatory Guide 1.137 is not applicable to HCGS, per its implementation section, HCGS complies with it, subject to exception of regulatory position C.1, which endorses ANSI N195-1976 Section 8.2.d and as modified by Technical Specification Amendment Nos. 74 and 100. HCGS has a fuel-oil storage tank low-low and low alarm. High level protection is provided by the common fill isolation valve that automatically closes at the storage tank high-high level setpoint. Compliance with Regulatory Guide 1.137 has been amended by the NRC in a letter dated Nov. 22, 1993 to provide an acceptable alternative to the guidance and recommendations contained in ANSI N195-1976 and RG 1.137, Revision 1, and complies with the requirements of GDC 5 and 17 as well as satisfying the intent of SRP Section 9.5.4, Section I.1.d.

1.8.1.138 <u>Conformance to Regulatory Guide 1.138, Revision 0, April 1978: Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants</u>

For new investigations conducted after December 1, 1978, HCGS complies with Regulatory Guide 1.138.

Position C.3 references Regulatory Guide 1.132. Compliance with Regulatory Guide 1.132 is discussed in Section 1.8.1.132.

For further discussion of site investigations, see Sections 2.4 and 2.5.

1.8.1.139 <u>Conformance to Regulatory Guide 1.139, Revision 0, May 1978: Guidance for Residual Heat Removal</u>

Although the HCGS RHR design was completed before the issuance of this Regulatory Guide, which provides guidance on shutdown cooling mode design, the HCGS design satisfies the intent of the Regulatory Guide, subject to the following clarifications:

1. Provision of shutdown cooling, assuming the most limiting single active failure, loss of the common suction line due to valve failure to open, as discussed in Position C.1 of the Regulatory Guide, can also be accomplished by an alternate flow path. In the alternate method, the RHR pump takes suction from the suppression pool and discharges to the reactor vessel via the RHR heat exchanger. Flow returns from the vessel to the suppression pool via manually opened Automatic Depressurization System (ADS) valves. A safety-grade air supply is available for ADS valve actuation, as discussed in Section 9.3.1. A variation of this method is to pump to the vessel with a core spray pump and operate the RHR system in the suppression pool cooling mode.

2. Regarding Position C.2.a of the Regulatory Guide, which discusses reactor high pressure interlocks and alarms, HCGS conforms with the intent in that the two suction valves, E11-HV-F008 and E11-HV-F009, are interlocked with reactor pressure. Two out of two low reactor pressure signals must be present to permit opening. Upon a high pressure signal, the valves close, and the pump trips. A pump trip activates an "RHR system out of service" alarm that annunciates in the main control room. High pressure is displayed on CRTs and the computer. Loss of power to the valve control logic causes suction valve closure and pump trip.

3. The RHR system is a low pressure system that when aligned to the reactor coolant systems operates only when the reactor pressure has been brought down to 100 psig. The RHR system isolates if reactor vessel pressure exceeds this design setpoint.

   When the RHR system is not in operation, relief valves protect the system from excess pressure due to thermal expansion or leakback from the reactor through isolation valves. These relief valves discharge to the suppression pool.

4. The RHR design is considered to conform to the pump protection discussion in Position C.4 of the Regulatory Guide in that the pump motor has thermal overload protection, and the stator and bearing temperatures are monitored on the plant computer.

   Cavitation is considered in pump selection and piping layout. Calculations have been performed to verify that adequate NPSH exists at maximum suppression pool temperature (212°F) and maximum pump runout flow.

5. On-line testing capability of isolation valve operability and interlock circuits, as discussed in Position C.5 of the Regulatory Guide, is not provided. However, the system is periodically tested as discussed in Section 16, the Hope Creek Standard Technical Specifications.

1.8.1.140 Conformance to Regulatory Guide 1.140, Revision 1, October 1979: Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants

Although Regulatory Guide 1.140 is not applicable to HCGS, per its implementation section, HCGS complies with it, subject to exceptions and clarifications stated below:

Concerning Position C.2.a, the reactor building normally uses the Reactor Building Ventilation System (RBVS) exhaust system, which includes prefilters and HEPA filters but no charcoal filters. The radwaste area, fume hoods, and chemistry lab area exhaust systems have only prefilters and HEPA filters. The turbine building equipment compartment exhaust system has been designed with a provisional filter plenum which, at the present time, does not include filters.

Position C.2.b has not been strictly observed because the RBVS exhaust system exhausts 48,000 cfm per each filter plenum. The radwaste area exhaust system fans are set to provide a nominal 33,800 cfm per each exhaust filter plenum since the tank vent has only 1000 cfm per filter plenum.

Position C.2.f of Regulatory Guide 1.140 - Table 4-3 of ANSI N509 - 1980 Section 4.12 was used as the acceptance criteria for maximum allowable leakage in ductwork.

Regulatory Guide 1.140 references ANSI N510-1975. HCGS will use the ANSI N510-1980 issue.

For further discussion of the atmosphere cleanup systems, see Section 9.4.

1.8.1.141 Conformance to Regulatory Guide 1.141, Revision 0, April 1978: Containment Isolation Provisions for Fluid Systems

Although Regulatory Guide 1.141 is not applicable to HCGS, per its implementation section, HCGS complies with the requirements of ANSI N271-1976 (ANS-56.2) as modified and interpreted by Regulatory Guide 1.141, with the exceptions and clarifications discussed below.

ANSI Section 3.1, General, references an American National Standard and a draft standard for guidance on the development of quality group classifications. The criteria for quality group classifications at the HCGS is based on the guidelines of Regulatory Guide 1.26.

When it is not practical to provide one isolation valve inside and one outside containment, and both valves are located outside primary containment, Section 3.6.4 requires that the valve nearest primary containment be enclosed in a protective leaktight or controlled leakage housing to prevent leakage to the atmosphere. Similarly, when greater safety is achieved by the use of a single isolation valve, Section 3.6.5 requires that the isolation valve be enclosed in a protective housing. In the HCGS design, no protective housing is provided. Nonetheless, the design is adequate in that any leakage will be collected within the Reactor Building, prior to filtration, dilution, and final release to the environment. Also, extensive leakage will trip sump level alarms, which will alert the main control room operators.

Appendix A depicts typical isolation valve arrangements for BWRs. The arrangements are applicable to Mark III containment designs and do not apply to HCGS.

For further discussion of containment isolation, see Section 6.2.4. ANSI Section 3.6.2, Instrument Lines, states that NRC Regulatory Guide 1.11 provides suitable bases for demonstrating the acceptability of instrument lines penetrating primary containment.

See Section 1.8.1.11 for discussion of compliance with Regulatory Guide 1.11.

1.8.1.142 Conformance to Regulatory Guide 1.142, Revision 1, October 1981: Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments)

Regulatory Guide 1.142 is not applicable to HCGS per its implementation section. SRP Section 3.8.4, Acceptance Criteria II.2, requires that Seismic Category I structures be designed in accordance with ACI 349-1976 as augmented by Regulatory Guide 1.142. HCGS Seismic Category I structures are designed based on ACI 318-1971.

A review of the design of the HCGS Seismic Category I structures indicates that there is no impact due to differences in the structural acceptance criteria between ACI 318-71 and ACI 349-76 as augmented by Regulatory Guide 1.142. See Design Criteria Comparison Table 1.8-4.

The load combinations used are in conformance with the following SRP sections except that the 0.9 load factor on dead load as required by ACI 349-76 was not used:

Structures	SRP Section
Primary Containment Internal Concrete Structures	3.8.3.II.3.b
Other Seismic Category I Concrete Structures	3.8.4.II.3.b

Based on parametric analyses, an adequate design margin exists to compensate for the effects of the reduced dead load factor.

See Section 3.8.3 for discussion of the design of concrete structures.

1.8.1.143 Conformance to Regulatory Guide 1.143, Revision 1, October 1979: Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light Water Cooled Nuclear Power Plants

Although Regulatory Guide 1.143 is not applicable to HCGS, per its implementation section, HCGS complies with it, with the clarifications stated below.

Positions C.1.1.2, C.2.1.2, C.3.1.2, and Table 1 of Regulatory Guide 1.143 require that all material specifications for pressure-retaining components within the radioactive process boundary conform to ASME B&PV Code, Section II. In addition, they require that piping materials conform to both the ASME and the identical ASTM specification, and they permit substitution of manufacturers' standards, instead of the ASME specification, in the case of pump materials. Although Regulatory Guide 1.143 does not explicitly address in-line process components, sight flow glasses, Y-strainers, and steam traps procured by the architect/engineer, and the orifice plates and conductivity elements in the NSSS scope of supply do not have certificates of compliance for the materials specified. Also, the records of shop inspection, required by Table 1, for the Y-strainers and the steam traps are not available from the supplier.

Nevertheless, the quality assurance measures taken provide the reasonable assurance needed to protect the health and safety of the public and that of plant operating personnel.

Position C.1.2.1 requires that the designated high liquid level conditions should actuate alarms both locally and in the control room. For all tanks, a high liquid level condition actuates an alarm in the radwaste control room only. There are no local alarms since the tank rooms are controlled areas and normally unmanned.

Position C.4.3 requires that process lines should not be less than 3/4 inch (nominal). The crystallizer concentrates and slurry waste transfer lines to the extruder/evaporators are 1/2 inch nominal, in order to maintain acceptable flow velocities to prevent settling in the lines**. The fluid flowrates are on the order of one (1) gpm as shown in Table 11.4-7 and on Plant Drawing M-68-0.

1.8.1.144 Conformance to Regulatory Guide 1.144, Revision 1, September 1980: Auditing of Quality Assurance Programs for Nuclear Power Plants

NRC Regulatory Guide 1.144 was withdrawn by the NRC on July 31, 1991. HCGS is committed to the requirements of NQA-1-1994.

** Note: Crystallizer and Extruder Evaporators are abandoned in place.

For further discussion of quality assurance, see Section 17.

1.8.1.145 Conformance to Regulatory Guide 1.145, Revision 0, August 1979: Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants

HCGS complies with Regulatory Guide 1.145.

1.8.1.146 Conformance to Regulatory Guide 1.146, Revision 0, August 1980: Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

NRC Regulatory Guide 1.146 was withdrawn by the NRC on July 31, 1991. HCGS is committed to the requirements of NQA-1-1994.

For further discussion of quality assurance, see Section 17.

1.8.1.147 Conformance to Regulatory Guide 1.147, (Latest Revision): Inservice Inspection Code Case Acceptability ASME Section XI Division 1

HCGS complies with Regulatory Guide 1.147.

For further discussion of inservice inspection, see Sections 3.9.6, 5.2.4, and 6.6.

1.8.1.148 Conformance to Regulatory Guide 1.148, Revision 0, March 1981; Functional Specification for Active Valve Assemblies in Systems Important to Safety in Nuclear Power Plants

In accordance with Paragraph D, Implementation, Regulatory Guide 1.148 is not currently applicable to HCGS. If, in the future, replacement valves are ordered or modifications are made to systems important to safety, the guidelines of ANSI N278.1-1975, as modified and endorsed by Regulatory Guide 1.148, will be addressed and/or implemented. For discussion of the function specification requirements of active valve assemblies, see Section 3.9.3.

1.8.1.149 Conformance to Regulatory Guide 1.149, Revision 0, April 1981; Nuclear Power Plant Simulator for Use in Operator Training

NOTE: Regulatory Guide 1.149, Revision 0, has been superseded by 10CFR55.45(b) and 10CFR55.46.

NOTE: Regulatory Guide 1.150 was been superseded by 10CFR50.55a(g)(6)(ii)(C)(1), "Inservice inspection requirements".

1.8.1.155 Conformance to Regulatory Guide 1.155, Revision 0, August 1988: Station Blackout

HCGS complies with Regulatory Guide 1.155 as described in Section 1.15.

1.8.1.181 Conformance to Regulatory Guide 1.181, Revision 0, September 1999: Content Of The Updated Final Safety Analysis Report in Accordance With 10 CFR 50.71(e)

The PSEG Nuclear procedures for updating the UFSAR are based on NEI 98-03, Revision 1, which is endorsed by Regulatory Guide 1.181. The purpose of NEI 98-03 is to provide licensees with guidance for updating their FSARs consistent with the requirements of 10 CFR 50.71(e). Guidance is also provided for making voluntary modifications to UFSARs (i.e., removal, reformatting and simplification of information, as appropriate) to improve their focus, clarity and maintainability.

1.8.1.183 Conformance to Regulatory Guide 1.183, Revision 0, July 2000: Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Plants

HCGS complies with Regulatory Guide 1.183. See Sections 6 and 15 for discussions of the radiological consequences of accidents.

1.8.2 NSSS Assessment of Conformance

1.8.2.1 Purpose

The purpose of this section is to outline the compliance of the Hope Creek Generating Station (HCGS) design with Regulatory Guides issued by the NRC.

1.8.2.2 Compliance Assessment Method-NSSS

Table 1.8-1 presents an assessment of the GE Nuclear Steam Supply System (NSSS) compliance with NRC Regulatory Guides.

The NRC (AEC) began in 1970 to issue Regulatory Guides (Safety Guides), which state in detail methods acceptable to the NRC staff of meeting applicable Federal Regulations. Since that time, new and revised Regulatory Guides have been issued on an ongoing basis.

During the Construction Permit stage of HCGS, GE agreed in the Preliminary Safety Analysis Report (PSAR) to comply with the appropriate Regulatory Guides issued at that time. These Regulatory Guides are treated by GE as part of the design basis for HCGS. Subsequent to the Construction Permit stage, additional Regulatory Guides applicable to BWRs were issued. The HCGS design inherently meets, with alternate position in some cases, most of these Regulatory Guides. However, the Regulatory Guides issued subsequent to Construction Permit stage are not considered a part of the formal plant design basis.

Table 1.8-1 lists the applicable Regulatory Guides 1.1 through 1.120, 1.128, 1.129, and 1.131, except for those Regulatory Guides that have been withdrawn or which do not apply to BWRs. The table also differentiates between those Regulatory Guides that are part of the design basis, i.e., GE committed to meet them in the PSAR, and those Regulatory Guides against which the design has been assessed.

The actual description of how the design meets a Regulatory Guide is included in the FSAR text in the location where Regulatory Guide 1.70, Revision 3, indicates that it be addressed. The table identifies the specific revision of all Regulatory Guides addressed.

Using the approach and methods discussed above, Table 1.8-1 provides a concise and accurate definition of Regulatory Guide compliance for the NSSS portion of HCGS.

1.8.3 References

1.8-1 General Electric, "Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 plants," NEDO-24057A, April 1981.

1.8-2 General Electric, "Recirculation Pump Shaft Seal Leakage Analysis," NEDO-24083, November 1978.

1.8-3 Arthur D. Little, Inc, "Analysis of Potential Effects of Waterborne Traffic On the Safety of The Control Room and Water Intakes at Hope Creek Generating Station," September 1974.

1.8-4 Deleted.

1.8-5 General Electric, "Nuclear Energy Business Operations Boiling Water Reactor Quality Assurance Program Description," NEDO-11209-0A, Latest NRC-Accepted Revision.

TABLE 1.8-1

REGULATORY GUIDE ASSESSMENT-NSSS

Regulatory Guide		Reference[2]	GE NSSS[3]	Compliance[1] Compliance	Design Basis Alternate	Design Basis	Capability
1.1,	Net Positive Suction Head for ECCS	Section 6.3.2.2	X	X	-	0	-
1.2,	Thermal Shock to Reactor Pressure Vessels	Section 5.3.3.1	X	X	-	0	-
1.3,	Assumptions Used for Radiological Consequences of a LOCA BWR	-	NA	-	-	-	-
1.5,	Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break	-	NA	-	-	-	-
1.6,	Independence Between Redundant Standby (Onsite) Power Sources	-	X	X	-	0	-
1.7,	Control of Combustible Gas Concentrations in Containment	-	NA	-	-	-	-
1.8,	Personnel Selection and Training	-	NA	-	-	-	-
1.9,	Selection of Diesel Generator Set Capacity for Standby Power Supplies	-	NA	-	-	-	-
1.11,	Instrument Lines Penetrating Primary Reactor Containment Supplement to Safety Guide 11, Backfitting Considerations	-	NA	-	-	-	-
1.12,	Instrumentation for Earthquakes	-	NA	-	-	-	-
1.13	Spent Fuel Storage Facility Design Basis	Section 9.1.4.3	X	X	-	0	-
1.14,	Reactor Coolant Pump Flywheel Integrity	-	NA	-	-	-	-
1.16,	Reporting of Operating Information	-	NA	-	-	-	-
1.17,	Protection of Nuclear Power Plants Against Industrial Sabotage	-	NA	-	-	-	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Compliance[1]: Design Basis Alternate	Compliance[1]: Design Basis	Compliance[1]: Capability
1.20, Comprehensive Vibration Assessment Program for Reactor Internals	Section 3.9.2.6.1	X	X	-	2	-
1.21, Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents	-	NA	-	-	-	-
1.22, Periodic Testing of Protection System Actuation Functions	Sections 7.1.2.4, 7.2.2.3, 7.3.2.1, 7.4.2.1, 7.4.2.2, 7.6.2.2, 7.6.2.3, and 7.6.2.5	X	X	0	0	-
1.23, Onsite Meteorological Programs	-	NA	-	-	-	-
1.25, Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident	-	NA	-	-	-	-
1.26, Quality Group Classifications & Standards for Water-, Steam-, & Radioactive Waste-Containing Components	Sections 3.2.2 and 9.3.5.3	X	X	-	0,2	-
1.27, Ultimate Heat Sink for Nuclear Power Plants	-	NA	-	-	-	-
1.28, Quality Assurance Program Requirements (Design and Construction)[4]	Chapter 17	X	X	2	2	-
1.29, Seismic Design Classification	Sections 3.2.1, 5.4.8.1, 7.1.2.4, 7.4.2.1, 7.4.2.2, 7.6.2.5, and 9.3.5.3	X	X	1	1	-
1.30, Quality Assurance Requirements for the Installation, Inspection, & Testing of Instrumentation and Electric Equipment[4]	Sections 3.11 7.1.2.4, 7.4.2.1, and 7.6.2.5	X	X	-	0	-

TABLE 1.8-1 (Cont)

Regulatory Guide		Reference (2)	GE NSSS (3)	Compliance (1): Compliance	Compliance (1): Design Basis Alternate	Compliance (1): Design Basis	Capability
1.31,	Control of Ferrite Content in Stainless Steel Weld Metal	Sections 4.5.1.2, 4.5.2.4, 5.2.3.4, and 5.3.1.4	X	X	-	1,3,4	-
1.32,	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants	Section 8.3.1.5	X	-	-	-	2
1.33,	Quality Assurance Program Requirements (Operation)	-	NA	-	-	-	-
1.34,	Control of Electroslag Weld Properties	Sections 4.5.2.4, 5.2.3.3, and 5.3.1.4	X	-	-	-	-
1.35,	Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment	-	NA	-	-	-	-
1.36,	Nonmetallic Thermal Insulation for Austenitic Stainless Steel	Section 4.5.2.4	X	-	-	-	0
1.37,	Quality Assurance Requirements for Cleaning of Fluid Systems (Construction) (4)	Sections 4.5.1.4	X	X	0	0	-
1.38,	QA Requirements for Packaging, Shipping, Receiving, Storage, & Handling (4)	Chapter 17	X	X	2	2	-
1.39,	Housekeeping Requirements for Water-Cooled Nuclear Power Plants (4)	Chapter 17	X	X	-	2	-
1.40,	Qualification Tests of Continuous Duty Motors Installed Inside the Containment	-	NA	-	-	-	-
1.41,	Preop Tests of Redundant Onsite Electric Power Systems	-	NA	-	-	-	-
1.43,	Control of Stainless Steel Weld Cladding of Low-Alloy Components	Sections 5.2.3, and 5.3.1.4	X	-	-	-	0

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Compliance[1]: Design Basis Alternate	Compliance[1]: Design Basis	Compliance[1]: Capability
1.44, Control of the Use of Sensitized Stainless Steel	Sections 4.5.1.2, 5.2.3.4, and 5.3.1.4	X	X	0	0	-
1.45, Reactor Coolant Pressure Boundary Leakage Detection Systems	-	-	-	-	-	-
1.46, Protection Against Pipe Whip Inside Containment	Section 3.6.2.6	X	X	-	0	-
1.47, Bypassed & Inoperable Status Indication for Nuclear Power Plant Safety Systems	Sections 7.1.2.4, 7.4.2.1, 7.4.2.2, 7.6.2.4, and 7.6.2.5	X	X	-	0	-
1.48, Design Limits & Loading Combinations for Seismic Category I Fluid System Components	-	NA	-	-	-	-
1.49, Power Levels of Nuclear Power Plants	Section 15.0.5	X	-	-	-	1
1.50, Control of Preheat Temperature for Welding of Low-Alloy Steel	Sections 5.2.3.3 and 5.3.1.4	X	-	-	-	0
1.52, Design, Testing, & Maintenance Criteria for Atmosphere Cleanup System Air Filtration & Absorption Units	-	NA	-	-	-	-
1.53, Application of the Single-Failure Criterion	Sections 7.1.2.4, 7.2.2.3, 7.3.2.1, and 7.6.2.3	X	X	-	0	-
1.54, QA Requirements for Protective Coatings[4]	Section 6.1.2	X	X	-	0	-
1.55, Concrete Placement in Category I Structures	-	NA	-	-	-	-
1.56, Maintenance of Water Purity in BWRs	Sections 5.2.3.2 and 5.4.8.1	X	X	-	1	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Design Basis Alternate	Design Basis	Capability
1.57, Design Limits & Loading Combinations for Metal Primary Reactor Containment	-	NA	-	-	1	-
1.58, Qualification of Nuclear Power Plant Inspection, Examination, & Testing Personnel[4]	Chapter 17	X	X	1	1	-
1.59, Design Basis for Floods for Nuclear Power Plants	-	NA	-	-	-	-
1.60, Design Response Spectra for Seismic Design of Nuclear Power Plants	-	X	-	-	-	1
1.61, Damping Values for Seismic Design of Nuclear Power Plants	Section 3.7.1	X	X	-	0	-
1.62, Manual Initiation of Protective Actions	Sections 7.1.2.4, 7.2.2.3, 7.3.2.1, 7.4.2.1, and 7.4.2.2	X	X	-	0	-
1.63, Electric Penetration Assemblies in Containment Structures	-	NA	-	-	-	-
1.64, QA Requirements for Design PSAR of Nuclear Power Plants[4]	Chapter 17	X	X	2	2	-
1.65, Materials & Inspection for Reactor Vessel Closure Studs	Section 5.3.1.7	X	-	-	-	0
1.66, Nondestructive Examination of Tubular Products	Sections 5.2.3.3 and 5.2.3.4	X	-	-	-	0
1.67, Installation of Overpressure Protection Devices	-	NA	-	-	-	-
1.68, Initial Test Programs for Water-Cooled Reactor Power Plants	Section 14.2	NA	-	-	-	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Compliance[1]: Design Basis Alternate	Compliance[1]: Design Basis	Compliance[1]: Capability
1.68.1, Preop & Initial Startup Testing of FW & Condensate Systems for BWR	Section 14.2					
1.68.2, Initial Startup Test Program to Demonstrate Remote Shutdown Capability	Section 14.2					
1.69, Concrete Radiation Shields for Nuclear Power Plants	-	NA	-	-	-	-
1.70, Standard Format & Content of Safety Analysis Reports for Nuclear Power Plants	-	X	X	-	3	-
1.71, Welder Qualification for Areas of Limited Accessibility	Sections 4.5.2.4, 5.2.3.3, 5.2.3.4, and 5.3.1.4	X	-	-	-	0
1.72, Spray Pond Plastic Piping	-	NA	-	-	-	-
1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants	Sections 3.11 and 7.1.2.4	NA	-	-	-	0
1.74, QA Terms & Definitions[4]	Chapter 17	X	X	-	2	-
1.75, Physical Independence of Electric System	Sections 7.1.2.4, 7.4.2.1, 7.6.2.2, 7.6.2.4 and 7.6.2.5	X	X	1	1	-
1.76, Design Basis Tornado for Nuclear Power Plants	-	NA	-	-	-	-
1.78, Assumptions for Evaluating the Habitability of a Hazardous Chemical Release	-	NA	-	-	-	-
1.80, Preop Testing of Instrument Air Systems	-	NA	-	-	-	-

Regulatory Guide		Reference[2]	GE NSSS[3]	Compliance[1] Compliance	Design Basis Alternate	Design Basis	Capability
1.81,	Shared Emergency & Shutdown Electric Systems for Multiunit Nuclear Power Plants	-	NA	-	-	-	-
1.82,	Sumps for ECC & Containment Spray Systems	-	NA	-	-	-	-
1.84,	Code Case Acceptability - ASME Section III Design & Fabrication	Section 5.2.1.2	X	X	-	NA	-
1.85,	Code Case Acceptability - ASME Section III Materials	Section 5.2.1.2	X	X	-	NA	-
1.86,	Termination of Operating Licenses for Nuclear Reactors	-	NA	-	-	-	-
1.88,	Collection, Storage, & Maintenance of QA Records[4]	Chapter 17	X	X	2	2	-
1.89,	Qualification of Class 1E Equipment for Nuclear Power Plants	Sections 3.11 and 7.1.2.4	X	-	-	-	0
1.90,	Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons	-	NA	-	-	-	-
1.91,	Evaluation of Explosions Postulated to Occur on Transportation Routes	-	NA	-	-	-	-
1.92,	Combining Model Responses & Spatial Components in Seismic Response Analysis	Sections 3.7.3.7 and 3.9.2.3	X	-	-	-	1
1.93,	Availability of Electric Power Sources	-	NA	-	-	-	-
1.94,	QA for Installation, Inspection, & Testing of Structural Concrete & Structural Steel During Construction	-	NA	-	-	-	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference (2)	GE NSSS (3)	Compliance (1): Compliance	Design Basis Alternate	Design Basis	Capability
1.95, Protection of Control Room Operators Against an Accidental Chlorine Release	-	NA	-	-	-	-
1.96, Design of MSIV Leakage Control Systems for BWR Power Plants	-	NA	-	-	-	-
1.97, Instrumentation for LWR Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	-	NA	-	-	-	-
1.99, Radiation Embrittlement of Reactor Vessel Materials	Section 5.3.1.4	NA	-	-	-	2
1.100, Seismic Qualification of Electric Equipment for Nuclear Power Plants	Sections 3.10 and 7.1.2.4	X	-	-	-	-
1.101, Emergency Planning for Nuclear Power Plants	-	NA	-	-	-	-
1.102, Flood Protection for Nuclear Power Plants	-	NA	-	-	-	-
1.105, Instrument Setpoints	Section 7.1.2.4	X	-	-	-	1
1.106, Thermal Overload Protection for Electric Motors on Motor-Operated Valves	-	NA	-	-	-	-
1.108, Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants	-	NA	-	-	-	-
1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents	-	NA	-	-	-	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Compliance[1]: Design Basis Alternate	Compliance[1]: Design Basis	Compliance[1]: Capability
1.111, Methods for Estimating Atmosphere Transport and Dispersion of Gaseous Effluents in Routine Releases from Light Water Cooled Reactors.	-	NA	-	-	-	-
1.112, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Cooled Power Reactors	-	NA	-	-	-	-
1.113, Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I	-	NA	-	-	-	-
1.114, Guidance on Being Operator at the Controls of a Nuclear Power Plant	-	NA	-	-	-	-
1.115, Protection Against Low Trajectory Trubine Missles	-	NA	-	-	-	-
1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems[4]	Chapter 17	X	X	-	0	-
1.117, Tornado Design Classification	-	NA	-	-	-	-
1.118, Periodic Testing of Electric Power and Protection Systems	Section 7.1.2.4	NA	-	-	-	2
1.120, Fire Protection Guidelines for Nuclear Power Plants	-	NA	-	-	-	-
1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants[4]	Chapter 17	X	X	1	1	-

TABLE 1.8-1 (Cont)

Regulatory Guide	Reference[2]	GE NSSS[3]	Compliance[1]: Compliance	Compliance[1]: Design Basis Alternate	Compliance[1]: Design Basis	Compliance[1]: Capability
1.128, Installation, Design, and Installation of Large Lead Storage Batteries for Nuclear Power Plants	-	NA	-	-	-	-
1.129, Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants	-	NA	-	-	-	-
1.131, Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants	-	NA	-	-	-	-

(1) Compliance assessment:

a. Design basis: A number is placed in this column to indicate the Regulatory Guide revision that is a NSSS design basis requirement for this plant. Where no number is shown, the guide was not an NSSS design basis (See Section 1.8.2). When two numbers are shown, they indicate the revision numbers for guides applicable to equipment procured and systems released before and after December, 1974, respectively.

b. Compliance: An "X" is placed in this column to indicate compliance if the design basis guide was used by GE with or without an alternate position taken.

c. Design basis alternate: An "X" is placed in this column to indicate the guide revision number to which an alternate position is taken.

d. Capability: A number is placed in this column to indicate the guide revision by which the capability of the NSSS portion of the HCGS was assessed.

(2) Reference:

The number in this column indicates the section in which the compliance assessment for the guide indicated can be found.

(3) GE NSSS - An "X" is placed under GE NSSS to indicate that GE is responsible for the implementation or assessment of the Regulatory Guide shown. This column is used to designate "NA" when the guide shown is not applicable to the NSSS scope of supply for the HCGS.

TABLE 1.8-1 (Cont)

(4) Descriptions of compliance with quality assurance related Regulatory Guides are not requested by Regulatory Guide 1.70, Revision 3, since they relate to requirements that are implemented during the design, are resolved at the PSAR, i.e., Construction Permit, stage of the project, and are not pertinent at the FSAR, i.e., Operating License, stage. Compliance descriptions for quality assurance related Regulatory Guides may be found in Reference 1.8.5.

TABLE 1.8-2

RELATIVE NEUTRON FLUX VERSUS TIME[1]

Leakage rate, gpm (ramp rate, ¢/min)[2]

Percent of Power	1(0.03)		5(0.15)		20(0.60)	
	Σ	Δ	Σ	Δ	Σ	Δ
5×10^{-8}	-555	500	-111	100	-27.75	25
5×10^{-7}	-55	50	-11	10	-2.75	2.5
5×10^{-6}	-5	5	-1	1	-0.25	0.25
5×10^{-5}	0		0		0	
5×10^{-4}	0.8	0.8	0.36	0.36	0.18	0.18
5×10^{-3}	1.33	0.53	0.51	0.15	0.25	0.07
5×10^{-2}	1.59	0.26	0.62	0.11	0.31	0.06
5×10^{-1}	1.80	0.21	0.72	0.10	0.36	0.05
5×10^{0}	1.89	0.09	0.80	0.08	0.40	0.04

(1) Shutdown flux = 5×10^{-8} percent of power.

(2) Σ = total number of hours; Δ = hours for neutron flux to increase by one decade.

TABLE 1.8-3

USE OF CODE CASE N-242 ON RCPB PIPING
AND COMPONENTS

Item[1]	Tag/Spool No.	Application
Piping	1-AB-050-S19	Main Steam Line Drain
	1-AB-050-S20	Main Steam Line Drain
	1-BE-023-S01	Core Spray Injection
Safety-relief Valve	1-BC-PSV-4425	RHR shutdown suction
Venturies	1-FD-FO-N032	HPCI Steam Supply
	1-FC-FE-4155	RCIC Steam Supply

(1) Code Case N-242, Revision 0 is applicable to all items.

TABLE 1.8-4

DESIGN CRITERIA COMPARISON

ACI 349-76 and Regulatory Guide	ACI 318-71	Impact of Difference on HCGS
Not included	8.8.4 and 8.8.5	None. Permanent fillers are not used for HCGS Seismic Category I structures.
Not included	8.10 Alternate design method	None. Alternate design method is not used for HCGS Seismic Category I structures.
9.3 Required strength	9.3 Required strength	None. Load combinations for HCGS Seismic Category I concrete structures comply with SRP 3.8.3.II.3.b for containment internal concrete structures and SRP 3.8.4.II.3.b for other concrete structures.
9.3.3 Reduced load factors for dead and live load	9.3.4 Reduced load factors for dead and live load	None. As stated in Section 3.8.4.8.1, an adequate design margin exists to compensate for the effects of the reduced dead and live load factors.
9.4 Design strengths for reinforcement Yield strength (fy) limited to 60,000 psi	9.4 Design strengths for reinforcement Yield strength (fy) limited to 80,000 psi	None. Design of HCGS Seismic Category I structures is based on rebar yield strength (fy) = 60,000 psi
10.2.7 Assumptions β_1 shall not be taken less than 0.65	10.2.7 Assumptions No limitation on minimum value of β_1	None, since maximum value of design compressive strength, t_c' = 5000 psi for HCGS Seismic Category I structures.
10.17 Minimum reinforcement for massive concrete	Not included structures	None. A review of the design of the HCGS Seismic Category I structures indicates that ACI 349-76, Section 10.17 criteria is met.
11.16.6 Punching shear stress v_c = weighted average of v_{ch} and v_{cv} consider membrane stresses in wall.	11.16.6 refers to 11.10 where: $v_c = 4\sqrt{f_c'}$	None. A review of the design of HCGS Seismic Category I structures indicates that ACI 349-76, Section 11.16.7 criteria is met.

ACI 349-76 and Regulatory Guide	ACI 318-71	Impact of Difference on HCGS
12.10 Development of welded wire fabric Additional requirements for development length as compared with ACI 318-71.	12.10 Development of welded wire fabric	None. Welded wire fabric does not serve a safety related function for HCGS Seismic Category I structures.
13.3.1.5 Direct design method limitations "All loads shall be due to gravity only and uniformly distributed over the entire panel. The live load shall not exceed three times the dead load."	13.3.1.5 Direct design method limitations "The live load shall not exceed three times the dead load."	None. A review of the design of slabs for the HCGS Seismic Category I structures indicates that the direct design method is not used.
15.10 (b) Combined footings and mats "The Direct Design Method of Section 13.3 shall not be used to design combined footings and mats."	15.10 (b) Combined footings and mats Use of Section 13.3 is not excluded.	None. A review of the design of the foundation mats for the HCGS Seismic Category I structures indicates that the direct method is not used.
16.2.2 Precast Concrete Design "The design shall consider impact and other dynamic loading which may be imposed during transportation or erection."	16.2 Precast Concrete Design Dynamic loadings are not addressed in this section. These loads are considered to be part of Section 16.2.1.	None. Precast concrete is not used for HCGS Seismic Category I structures.

ACI 349-76 and Regulatory Guide	ACI 318-71	Impact of Difference on HCGS
16.4.2 Precast Concrete Details Embedded dowels or inserts may be placed while the concrete is in a plastic state provided that they are not required to be hooked or tied to reinforcement within concrete.	16.4.2 Precast Concrete Details Lifting devices shall have the capacity to support four times the member's weight.	None. Precast concrete is not used for HCGS Seismic Category I structures.
Chapter 18 - Prestressed Concrete Differences with ACI 318.71 for Sections 18.5, 18.9, 18.12 and 18.17.	Chapter 18 - Prestressed Concrete	None. Prestressed concrete is not used for HCGS Seismic Category I structures.
Chapter 19 - Shells This chapter applies to shell concrete structures having thicknesses equal to or greater than 12 inches.	Chapter 19 - Shells and Folded Plate Members This chapter applies to thin concrete structures only.	None. A review of the design of the HCGS Seismic Category I shell concrete structures indicates that ACI 349-76, Chapter 19 criteria is met.
Appendix A - Thermal Considerations	Not included	None. A review of the design of the HCGS Seismic Category I structures indicates that ACI 349-76, Appendix A criteria is met.
Appendix C - Special Provisions for Impulsive and Impactive Effects	Not included	A review of the design of the HCGS Seismic Category I concrete structures indicates that the criteria given in Appendix C of ACI 349-76 as amended by Regulatory Guide 1.142 are met.

1.9 STANDARD DESIGNS

This section is not applicable to Hope Creek Generating Station (HCGS) as it is not a standard design plant.

1.10 TMI-2 RELATED REQUIREMENTS FOR NEW OPERATING LICENSES

1.10.1 NUREG-0737, Clarification of the TMI Action Plan Requirements

Following the accident at Three Mile Island (TMI) Unit 2, the Nuclear Regulatory Commission (NRC) developed the TMI Action Plan, NUREG-0660, to provide a comprehensive and integrated plan for improving the safety of power reactors. NUREG-0737 was issued with an October 31, 1980 letter from D.G. Eisenhut, NRC, to licensees of operating power reactors and applicants for operating licenses forwarding specific TMI related requirements from NUREG-0660 which have been approved by the NRC for implementation at this time. In this NRC report, these specific requirements comprise a single document which includes additional information about implementation schedules, applicability, method of implementation review by the NRC, submittal dates, and clarification of technical positions. The total set of TMI related actions have been documented in NUREG-0660, but only those items that the NRC has approved for implementation to date are included in NUREG-0737.

Enclosure 2 to NUREG-0737 lists TMI Action Plan requirements for operating license applicants. FSAR Section 1.10.2 itemizes these requirements sequentially according to the NUREG-0737 number. Each item is accompanied by a response and/or reference to a section in the FSAR that further discusses how Public Service Electric and Gas Company (PSE&G) or the Hope Creek Generating Station (HCGS) design complies with the requirement. These responses will be revised periodically as ongoing efforts to address each requirement are completed.

1.10.2 TMI Action Plan Requirements for Applicants for an Operating License (Enclosure 2 to NUREG-0737)

I.A.1.1 Shift Technical Advisor

Position

Each applicant shall provide an on-shift technical advisor to the shift supervisor. The Shift Technical Advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls and the control room. The applicant shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

Clarification

1. Due to the similarity in the requirements for dedication to safety, training, and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment function. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

2. To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been the STAs

must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person who is normally the immediate supervisor of the shift supervisor to STA duties as defined herein.

3. It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the 10-minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence.

   We do not intend, at this time, to specify or advocate a minimum time onsite.

Response

The STA function will be provided, on shift, by an individual meeting the experience, education, and training requirements as specified in NUREG-0737 and ANS 3.1-1981 as endorsed by the NRC in Regulatory Guide 1.8, Revision 2. The proposed supervisory shift crew composition for conditions 1 through 3 consists of one Shift Manager, one Control Room Supervisor (CRS-SRO), two reactor operators/plant operators (RO/POs), and a person who is STA qualified.

The STA will have a Bachelor's degree or equivalent in a scientific or engineering discipline with specific training in: the response and analysis of the plant for transients and accidents; plant design and layout; and the capabilities of instrumentation and control in the control room; in accordance with the requirements of NUREG-0737, Section I.A.1.1.

Individuals can serve in a dual role capacity as either the SNSS/STA or NSS/STA. Any STA filling the dual role of STA/SRO (Reference 13.1.1.4.1.2) will meet the educational requirements of the "Commission Policy Statement on Engineering on Shift" (50 FR 43621) by having a: professional engineer's license; or bachelors degree from an accredited institution in an engineering, engineering technology, or physical sciences discipline (the engineering technology or physical sciences programs shall include courses in the physical, mathematical, or engineering sciences) as well as the specific training specified above.

During normal operations, the STA may be assigned responsibilities that pertain to the engineering aspects of ensuring safe operations of the plant.

See Section 13.1 for further discussion.

The content of the Shift Technical Advisor Training and Certification Program is described in the Nuclear Training Procedures Manual.

I.A.1.2 Shift Supervisor Responsibilities

Position

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room.

Clarification

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

2. Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

    (a) The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

    (b) The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

    (c) If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function that the shift supervisor is to provide for assuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

Response

A written policy describing the primary management responsibilities of OS-SROs and establishing their command duties was placed in effect September 12, 1979 and reissued by the senior corporate nuclear officer as VPN-PLP-01. Subsequently, the policy will be contained in the appropriate NBU administrative procedure(s).

The guidance of this policy, along with the duties, responsibilities, and authority of the OS-SRO, is promulgated in the appropriate NBU administrative procedure(s).

The shift command function responsibilities are promulgated in the appropriate NBU administrative procedures(s).

Shift administrative duties which detract from the OS-SRO's responsibility for safe operation of the plant will be assigned to clerks, the Operations Staff Group or "Work Control Group personnel" as appropriate.

See Section 13.1.2 for further discussion.

I.A.1.3 Shift Staffing

Position

Assure that the necessary number and availability of personnel to staff the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0578. Provisions should be made for an aide to the shift supervisor to assure that, over the long term, the shift supervisor is free of routine administrative duties.

Clarification

At any time a licensed nuclear unit is being operated in Modes 1-4 for a pressurized water reactor (power operation, startup, hot standby, or hot shutdown, respectively) or in Modes 1-3 for a boiling water reactor (power operation, startup, or hot shutdown, respectively), the minimum shift crew shall include two licensed senior reactor operators, one of whom shall be designated as the shift supervisor, two licensed reactor operators, and two unlicensed auxiliary operators. For a multi unit station, depending upon the station configuration, shift staffing may be adjusted to allow credit for licensed senior reactor operators and licensed reactor operators to serve as relief operators on more than one unit; however, these individuals must be properly licensed on each such unit. At all other times, for a unit loaded with fuel, the minimum shift crew shall include one shift supervisor who shall be a licensed senior reactor operator, one licensed reactor operator, and one unlicensed auxiliary operator.

Adjunct requirements to the shift staffing criteria stated above are as follows:

1. A shift supervisor with a senior reactor operator's license, who is also a member of the station supervisory staff, shall be onsite at all times when at least one unit is loaded with fuel.

2. A licensed senior reactor operator shall, at all times, be in the control room from which a reactor is being operated. The shift supervisor may from time to time act as relief operator for the licensed senior reactor operator assigned to the control room.

3. For any station with more than one reactor containing fuel, the number of licensed senior reactor operators onsite shall, at all times, be at least one more than the number of control rooms from which the reactors are being operated.

4. In addition to the licensed senior reactor operators specified in 1, 2, and 3 above, for each reactor containing fuel, a licensed reactor operator shall be in the control room at all times.

5. In addition to the operators specified in 1, 2, 3, and 4 above, for each control room from which a reactor is being operated, an additional licensed reactor operator shall be onsite at all times and available to serve as relief operator for that control room. As noted above, this individual may serve as relief operator for each unit being operated from that control room, provided (s)he holds a current license for each unit.

6. Auxiliary (non-licensed) operators shall be properly qualified to support the unit to which assigned.

7. In addition to the staffing requirements stated above, shift crew assignments during periods of core alterations shall

include a licensed senior reactor operator to directly supervise the core alterations. This licensed senior reactor operator may have fuel handling duties but shall not have other concurrent operational duties.

Licensees of operating plants and applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to staff the operational shifts are readily available in the event of an abnormal or emergency situation.

These administrative procedures shall also set forth a policy, the objective of which is to operate the plant with the required staff and develop working schedules such that use of overtime is avoided, to the extent practicable, for the plant staff who perform safety-related functions (e.g., senior reactor operators, health physicists, auxiliary operators, instrumentation and control technicians, and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980, discusses the concern of overtime work for members of the plant staff who perform safety-related functions.

We recognize that there are diverse opinions on the amount of overtime that would be considered permissible and that there is a lack of hard data on the effects of overtime beyond the generally recognized normal 8-hour working day, the effects of shift rotation, and other factors. We have initiated studies in this area. Until a firmer basis is developed on working hours, the administrative procedures shall include as an interim measure the following guidance, which generally follows that of IE Circular No. 80-02.

In the event that overtime must be used (excluding extended periods of shutdown for refueling, major maintenance, or major plant modifications), the following overtime restrictions should be followed.

1. An individual should not be permitted to work more than 12 hours straight (not including shift turnover time).

2. There should be a break of at least 12 hours (which can include shift turnover time) between all work periods.

3. An individual should not work more than 72 hours in any 7-day period.

4. An individual should not be required to work more than 14 consecutive days without having 2 consecutive days off.

However, recognizing that circumstances may arise requiring deviation from the above restrictions, such deviation shall be authorized by the Plant Manager or higher levels of management in accordance with published procedures and with appropriate documentation of the cause. If a reactor operator (RO) or senior reactor operator (SRO) has been working more than 12 hours during periods of extended shutdown (e.g., at duties away from the control board), such individuals shall not be assigned shift duty in the control room without at least a 12 hour break preceding such an assignment. We encourage the development of a staffing policy that would permit the licensed reactor operators and senior reactor operators to be periodically relieved of primary duties at the control board, such that periods of duty at the board do not exceed about 4 hours at a time. If a reactor operator is required to work in excess of 8 continuous hours, (s)he shall be periodically relieved of primary duties at the control board, such that periods of duty at the board do not exceed about 4 hours at a time.

The guidelines on overtime do not apply to the STA provided that the STA is provided sleeping accommodations and 10-minute availability is assured.

Operating license applicants shall complete these administrative procedures before fuel loading. Development and implementation of the administrative procedures at operating plants will be reviewed by the Office of Inspection and Enforcement beginning 90 days after July 31, 1980.

<u>Response</u>

See Section 13.1.2 for discussion on shift staffing and operating shift crews.

The appropriate NBU administrative procedure(s) establishes maximum work hours for licensed operators and implements current NRC policy including policy statement on nuclear power plant staff working hours dated 2/11/82 and Generic Letter 82-12.

Adequate shift coverage shall be maintained without routine excessive use of overtime. The objective shall be to have operating personnel work a nominal 40-hour week while the plant is operating to meet the rotating schedule requirements of the department. However, in the event that unforeseen problems require substantial amounts of overtime to be used; or during extended periods of shutdown for refueling, major maintenance, or major plant modifications, on a temporary basis; the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the cognizant department manager or higher levels of management, with documentation of the basis for granting the deviation.

Overtime shall be reviewed monthly by the Plant Manager or designee.

Shift staffing is described in Section 13.1.2 and in the appropriate NBU administrative procedure(s).

I.A.2.1 Immediate Upgrading of Operator and Senior Operator Training and Qualification

Position

Applicants for SRO license shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at specific plant) and no more than 2 years shall be academic or related technical training. After fuel loading, applicants shall have 1 year of experience as a licensed operator or equivalent.

Certifications that operator license applicants have learned to operate the controls shall be signed by the highest level of corporate management for plant operation.

Applicants must revise training programs to include training in heat transfer, fluid flow, thermodynamics, and plant transients.

Clarification

Applicants for SRO either come through the operations chain (C operator to B operator to A operator, etc.) or are degree-holding staff engineers who obtain licenses for backup purposes.

In the past, many individuals who came through the operator ranks were administered SRO examinations without first being an operator. This was clearly a poor practice and the letter of March 28, 1980 requires reactor operator experience for SRO applicants.

However, NRC does not wish to discourage staff engineers from becoming licensed SROs. The effort is encouraged because it forces engineers to broaden their knowledge about the plant and its operation.

In addition, in order to attract degree holding engineers to consider the shift supervisor's job as part of their career development, NRC should provide an alternate path to holding an operator's license for 1 year.

The track followed by a high-school graduate (a nondegreed individual) to become an SRO would be 4 years as a control room operator, at least one of which would be as a licensed operator, and participation in an SRO training program that includes 3 months on shift as an extra person.

The track followed by a degree holding engineer would be, at a minimum, 2 years of responsible nuclear power plant experience as a staff engineer, participation in an SRO training program equivalent to a cold applicant training program, and 3 months on shift as an extra person in training for an SRO position.

Holding these positions assures that individuals who will direct the license activities of licensed operators have had the necessary combination of education, training, and actual operating experience prior to assuming a supervisory role at the facility.

The staff realizes that the necessary knowledge and experience can be gained in a variety of ways. Consequently, credit for equivalent experience should be given to applicants for SRO licenses.

Applicants for SRO licenses at a facility may obtain their 1-year operating experience in a licensed capacity (operator or senior operator) at another nuclear power plant. In addition, actual operating experience in a position that is equivalent to a licensed operator or senior operator at military propulsion reactors will be acceptable on a one for one basis. Individual applicants must document this experience in their individual applications in sufficient detail so that the staff can make a finding regarding equivalency.

Applicants for SRO licenses who possess a degree in engineering or applicable sciences are deemed to meet the above requirements, provided they meet the requirements set forth in Sections A.1.a and A.2 in the enclosure in the letter from H.R. Denton to all power reactor applicants and licensees, dated March 28, 1980, and have participated in a training program equivalent to that of a cold senior operator applicant.

NRC has not imposed the 1-year experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

Response

All pre-core load SRO candidates will sit for a cold license and thus are not required to have been a licensed operator. The training program is designed to supply the equivalent of the experience they may lack and to meet the requirements of NUREG-0737 and ANS 3.1-1981.

Subsequent hot license candidates will meet the requirements of NUREG-0737, ANS 3.1-1981 as endorsed by the NRC in Regulatory Guide 1.8, Revision 2 and the H.R. Denton letter of 3/28/80.

I.A.2.3 Administration of Training Programs

Position

Pending accreditation of training institutions, training instructors who teach systems, integrated response, transient and simulator courses shall successfully complete a Senior Reactor Operator (SRO) examination prior to fuel loading and instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedure and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

Clarification

The above position is a short term position. In the future, accreditation of training institutions will include review of the procedure for certification of instructors. The certification of instructors may, or may not, include successful completion of an SRO examination.

The purpose of the examination is to provide NRC with reasonable assurance during the interim period that instructors are technically competent.

The requirement is directed to permanent members of training staff who teach the subjects listed above, including members of other organizations who routinely conduct training at the facility. There is no intention to require guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermodynamics, health physics, chemistry, etc.) to successfully complete an SRO examination. Nor is it intended to require a system expert, such as the instrument and control supervisor teaching the control rod drive system, to sit for an SRO examination.

Response

Prior to fuel loading, all instructors who teach systems, integrated response, transient response, and simulator courses will have successfully completed an approved SRO Cold Certification Program and/or have held an SRO license on a BWR facility. In addition, they will take as a minimum an NRC SRO instructor certification exam and actively participate in the SRO requalification program as required by the NRC.

Vendor personnel who teach the above courses will be approved by the principal training supervisor - Hope Creek or his designated representative.

I.A.3.1 Revise Scope and Criteria for Licensing Examinations

Position

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations.

Contents of the licensed operator requalification program shall be modified to include instruction in heat transfer fluid flow, thermodynamics and mitigation of accidents involving a degraded core.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license.

Requalification programs shall be modified to require specific reactivity control manipulations. Normal control manipulations, such as plant or reactor startups, must be performed. Control manipulations during abnormal or emergency operation shall be walked through and evaluated by a member of the training staff. An appropriate simulator may be used to satisfy the requirements for control manipulations.

Clarification

The clarification does not alter the staff's position regarding simulator examinations.

The clarification does provide additional preparation time for utility companies and NRC to meet examination requirements as stated. A study is under way to consider how similar a nonidentical simulator should be for a valid examination. In addition, present simulators are fully booked months in advance.

Application of this requirement was stated in June 1, 1980 to applicants where a simulator is located at the facility. Starting October 1, 1981, simulator examinations will be conducted for applicants of facilities that do not have simulators at the site.

NRC simulator examinations normally require 2 to 3 hours. Normally, two applicants are examined during this time period by two examiners.

Utility companies should make the necessary arrangements with an appropriate simulator training center to provide time for these examinations. Preferably these examinations should be scheduled consecutively with the balance of the examination. However, they may be scheduled no sooner than 2 weeks prior to and no later than 2 weeks after the balance of the examination.

Response

The requalification program meets the requirements of 10CFR55.

The Hope Creek simulator is operational for training and has been used for the operator requalification training program.

I.B.1.2 Evaluation of Organization and Management

Position

Corporate management of the utility owner of a nuclear power plant shall be sufficiently involved in the operational phase activities, including plant modifications, to assure a continual understanding of plant conditions and safety considerations. Corporate management shall establish safety standards for the operation and maintenance of the nuclear power plant. To these ends, each utility owner shall establish an organization, parts of which shall be located onsite, to: perform independent review and audits of plant activities; provide technical support to the plant staff for maintenance, modifications, operational problems, and operational analysis; and aid in the establishment of programmatic requirements for plant activities.

The licensee shall establish an integrated organizational arrangement to provide for the overall management of nuclear power plant operations. This organization shall provide for clear management control and effective lines of authority and communication between the organizational units involved in the management, technical support, and operation of the nuclear unit. The key characteristics of a typical organization arrangement are:

1. Integration of all necessary functional responsibilities under a single responsible head.

2. The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper level executive position.

Utility management shall establish a group, independent of the plant staff, but assigned onsite, to perform independent reviews of plant operational activities. The main functions of this group will be to evaluate the technical adequacy of all procedures and changes important to the safe operation of the facility and to provide continuing evaluation and assessment of the plant's operating experience and performance.

Response

See Section 13.1 for discussion of the PSE&G and HCGS organizations.

The Director – Nuclear Oversight reports directly to the President and Chief Nuclear Officer as discussed in Sections 13.1 and 17.2.

I.C.1 Short Term Accident Analysis and Procedure Review

Position

In our letters of September 13 and 27, October 10 and 30, and November 9, 1979, we required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, and to conduct operator retraining (see also Item I.A.2.1 of this report). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980, and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions were included in NUREG-0737, Item I.C.1.

Pending staff approval of the revised analysis and guidelines, the staff will continue the pilot monitoring of emergency procedures described in Item I.C.8 (NUREG-0660). The adequacy of the boiling water reactor vendor's guidelines will be identified to each near-term operating licensee during the emergency procedure review.

Response

All emergency operating procedures (EOPs) have been written following the guidelines of the BWR Owners Group-Emergency Procedures Committee, as long as the guidelines do not contradict existing NRC directives. The Procedures Generation Package (PGP) for the EOPs is provided in Appendix 13L. The procedures are available for NRC review.

Corrections will be made, as necessary, based on any NRC audits of these procedures.

The Emergency Operating Procedures for HCGS comply with NUREG-0737, Supplement 1, Section 7.0.

The Procedure Generation Package, Appendix 13L, which applied to initial revision of the Emergency Operating Procedures, has been deleted. The Writer's Guide, Verification Plan, Validation Plan and Training Plan have been retained in appropriate department administrative procedures and training programs for use in subsequent EOP revisions.

I.C.2 Shift Relief and Turnover Procedures

Position

The licensee shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist:

    (a) Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

    (b) Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included on the checklist.

(c) Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement. (This shall be recorded as a separate entry on the checklist.)

2. Checklists or logs shall be provided for completion by the offgoing and oncoming auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedures (for example, periodic independent verification of system alignments).

Response

The required checklists addressing shift turnover are specified in the appropriate NBU administrative procedure(s). The effectiveness of and compliance with the shift turnover procedure shall be audited in accordance with the Nuclear Oversight audit program as described in section 17.2 of the UFSAR.

I.C.3 Shift Supervisor Responsibilities

This item is included with Item I.A.1.2, Shift Supervisor Duties.

Response

A discussion of this item is provided in the response to Item I.A.1.2.

I.C.4 Control Room Access

Position

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support operation, and the predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access.

2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside the control room.

Response

The lines of responsibility and authority of the OS-SRO, or the individual assuming the control room command function (as previously promulgated in procedure VPN-PLP-01 and subsequently contained in the appropriate NBU administrative procedure(s)) permit limited access to the control room area. This authority is delineated in the appropriate NBU administrative procedure(s). This item is also discussed in the response to Item I.A.1.2.

I.C.5 Feedback of Operating Experience

Position

Each licensee will review its administrative procedures to assure that operating experience from within and outside the organization is continually provided to operators and other operational personnel and is incorporated in training programs.

Response

The appropriate NBU administrative procedure(s) provides the mechanism for the dissemination of information to station departments.

Industry operating experiences, including events occurring within the organization, are reviewed for applicability to Hope Creek by the Licensing and Regulation Department. Pertinent information is communicated to the appropriate department for their information, and any actions required are tracked until they have been satisfactorily completed. In addition, information is communicated to the Training Manager for incorporating new material into the training programs. The activities of the Licensing and Regulation Department with respect to operating experiences (i.e., INPO's SEE-IN Program) are governed by NBU administrative procedures.

Vendor technical documents describing the operation and maintenance of installed equipment and components associated with Hope Creek Generating Station shall be controlled in the following manner;

1. When vendor documents are received by disciplines within the NBU, these documents will be forwarded to Engineering for

review and approval for inclusion into the Vendor Document Control System.

2. Once approved by the cognizant engineer they will be assigned a unique number and distributed to all user departments, and incorporated in procedures and training as necessary.

Information on operating experience provided by the NRC through the I & E Bulletins/Information Notices, generic letters and letters on the docket are processed by the Nuclear Licensing and Regulation Department. These letters are distributed to various disciplines within the NBU for feedback of information. A response action form is utilized when a response or action is required and is monitored through the commitment tracking system to completion.

In addition, the Nuclear Training Center Administrative Procedures delineates the process of review and tracking of industry and station information that may have training implications.

I.C.6 Verify Correct Performance of Operating Activities

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations, and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Response

Verification of operating activities to provide a means of reducing human errors and to improve the quality of normal operations shall be assured by the following programs:

1. The appropriate NBU administrative procedure(s) shall:

   (a) Describe a program to track a system's status, i.e., operability.

   (b) Determine if a system's change in status results in the entering or clearing of a limiting condition for operation.

   (c) Describe a program to ensure that technical specification required operability of redundant safety-related equipment is verified.

   When like equipment is removed from service, this program shall also ensure the appropriate retest of equipment following preventive or corrective maintenance and prior to the equipment's return to an operable status.

   (d) Describe the independent verification program; this procedure will describe the method and technique for performing the independent verification.

   Individuals performing the independent verification associated with mechanical and electrical lineups shall, as a minimum, meet the requirements of

Section 13.2.1.1 and INPO Accredited Training Programs. Equipment operators performing the verifications will be those operators assigned to the control room supervisor on duty.

In some cases the independent verifications may be performed by a reactor operator/plant operator or shift technical advisor assigned to the on-duty shift.

2. The appropriate NBU administrative procedure(s) shall describe the method of valve sealing to prevent unauthorized operation of equipment. The valves that are required to be sealed shall be identified on design P&IDs. This information shall be incorporated into system valve lineups.

3. The appropriate NBU administrative procedure(s) shall contain the requirements for independent verification of safety-related system lineup and temporary modification for testing. In addition, this procedure will require, prior to start of testing, permission from designated operations personnel holding an SRO license.

4. The appropriate NBU administrative procedure(s) shall include reference to independent verification of installation and removal of Temporary Grounding Tags used on safety-related equipment.

5. The appropriate NBU administrative procedure(s) shall include requirements to obtain prior permission to work on plant equipment from designated operations personnel holding a SRO license.

6. The appropriate NBU administrative procedure(s) shall include independent verification requirements for installation of temporary modification on safety-related systems.

7. The appropriate NBU administrative procedure(s) shall establish the plant systems or subsystems requiring independent verification.

The above procedures shall contain identification of activities requiring independent verification, responsible person to perform the verification, and the method of documenting the performance verification for safety-related equipment. In addition, the appropriate NBU administrative procedure(s) shall specify periodic audit requirements of operational activities included, but not limited to, the above procedures.

I.C.7 NSSS Vendor Review of Procedures

Position

Obtain Nuclear Steam Supply System vendor review of power ascension and emergency operating procedures to further verify their adequacy.

Response

All NSSS startup test procedures from core load through power ascension will be reviewed by the NSSS vendor, General Electric Co. All non-NSSS startup test procedures will be reviewed by the appropriate system designer. This review, as well as vendor or designer review of test results, will be documented prior to completion of the Power Ascension (Phase III) Testing Program.

The HCGS Emergency Operating Procedures are being developed based on the NRC-approved BWR Owners' Group Emergency Procedure Guidelines (EPGs). Due to GE's involvement in the development of the EPGs, it has been determined that an additional NSSS vendor review of the plant specific Emergency Instructions is not necessary.

I.C.8 Pilot Monitoring of Selected Emergency Procedures for Near Term Operating License Applicants

Position

Correct emergency procedures as necessary based on the NRC audit of selected plant emergency operating procedures (e.g., small break loss-of-coolant accident, loss of feedwater, restart of engineered safety features following a loss of ac power and steam line break).

Response

A Procedure Generation Package (PGP) was prepared in accordance with Supplement 1 NUREG-0737. The PGP and plant specific Emergency Operating Procedures will be based on the NRC approved BWR Owners Group Emergency Procedure Guidelines (EPGs). As a result, it has been determined that an NRC review of the plant specific Emergency Operating Procedures is not necessary.

I.D.1 Control Room Design Reviews

Position

Licensees and applications for operating licenses are required to conduct a detailed control room design review to identify and correct design deficiencies. This detailed control room design review is expected to take about a year. Those applicants for operating licenses who are unable to complete this review prior to issuance of a license shall make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by us for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Clarification

Applicants for operating license who will be unable to complete the detailed control room review prior to issuance of a license are required to perform a preliminary control room design assessment to identify significant human factors problems. Applicants will find it of value to refer to the draft document, NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. We will evaluate the applicant's preliminary assessments including the performance by us of onsite reviews/audits. Our onsite review/audit will be on a schedule consistent with applicant licensing needs and will emphasize the following aspects of the control room:

1. The adequacy of information presented to the operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions.

2. The groupings of displays and the layout of panels.

3. Improvements in the safety monitoring and human factors enhancement of controls and control displays.

4. The communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, offsite telephone lines, and to other areas within the plant for normal and emergency operation.

5. The use of direct rather than derived signals for the presentation of process and safety information to the operator.

6. The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems.

7. The adequacy of operating procedures and operator training with respect to limitations of instrumentation displays in the control room.

8. The categorization of alarms, with unique definition of safety alarms.

9. The physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, we will require a copy of the applicant's preliminary assessment and additional information which will be used in formulating the details of the onsite review/audit.

Response

Essex Corporation has performed a detailed control room review to verify human factors considerations. The schedule and criteria for the review were based on NUREG-0700, and Supplement 1 to NUREG-0737. The control room design review summary report was submitted by a letter from R.L. Mittl, PSE&G, to A. Schwencer, NRC, dated August 14, 1984. See Section 18, Human Factors Engineering, for discussion.

I.D.2 Plant Safety Parameter Display Console

Position

Each applicant and licensee shall install a Safety Parameter Display System (SPDS) that will display to operating personnel a minimum set of parameters which define the safety status of the plant. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status.

Response

HCGS will install an SPDS in accordance with the requirements of Item I.D.2, as amended by Supplement 1 to NUREG-0737, and based on the guidelines detailed in SECY 82-111B. The displays are based on the displays developed by the BWR Owners' Group. The safety parameter display system is part of the Control Room Integrated Display System (Item XV.d of Table 3.2-1). The SPDS is discussed in Section 7.5.

I.G.1 Training During Low-Power Testing

Position

We require applicants for a new operating license to define and commit to a special low-power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training.

Clarification

Chapter 14 of the Final Safety Analysis Report describes the applicant's initial test program. The objectives of the initial test program include both training and the acquisition of technical data. This program has been determined by the staff to be acceptable as reported in Section 14 of this report. However, we require the applicant to perform additional testing and training beyond the requirements of the initial test program.

Response

Operators will participate in the low-power physics test program. Important activities and information from that program will be factored into the overall training program.

Any additional testing for training required by the NRC or GE will be conducted in accordance with prepared procedures and the results reviewed with operating personnel.

II.B.1 Reactor Coolant System Vents

Position

Each applicant shall install Reactor Coolant System and reactor vessel head high point vents remotely operable from the control room. The applicant must submit a description of the design, location, size, and power supply for the vent system along with results of analyses for loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10CFR50.46. In addition, procedures and supporting analysis for operator use of the vents that include the information available to the operator for initiating or terminating vent usage should be submitted. Documentation to meet this item is required by July 1, 1981 and implementation is required by July 1, 1982. Detailed clarification of this requirement is provided in Section II.B.1 of NUREG-0737.

Response

All the requirements are fulfilled by the HPCI and/or RCIC turbine operations or by the safety grade automatic depressurization system (ADS), described in Sections 5.2.2, 6.3.2, and 7.3.1, together with the long term safety grade air supply, described in Section 9.3.1. The point of connection of the vent lines to the vessel is such that accumulation of gases above this elevation in the vessel will not inhibit natural circulation cooling of the reactor core. The ADS valves are 5 of the 14 safety/relief valves. In addition, a reactor pressure vessel (RPV) head vent, which is operable from the control room, could be used as a backup to the ADS valve venting capability. The analysis demonstrating that the direct venting of noncondensable gases with possible high hydrogen concentrations does not result in violation of combustible gas concentration limits in containment is discussed in Section 6.2.5. Procedures for the operation of systems used to preclude the accumulation of noncondensible gases are available for review.

The design of the Reactor Coolant System (RCS) and RPV vent system is in agreement with the generic capabilities proposed by the BWR Owners' Group (BWROG), with the exception of isolation condensers. The BWROG position is summarized in NEDO-24782. The HPCI, RCIC, ADS, and containment instrument gas systems are Q-listed; as shown in Items V.C, VI, XV.b.1, and LXVII.b of Table 3.2-1. The RPV head vent is Q-listed but not Class 1E (Item I.c of Table 3.2-1).

II.B.2 Plant Shielding

Position

With the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," and Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors" (i.e., the equivalent of 50 percent of the core radioiodine, 100 percent of the core noble gas inventory, and 1 percent of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding-design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during post accident operations of these systems.

Each licensee shall provide for adequate access to vital areas of protection of safety equipment by design changes, increased permanent or temporary shielding, or post accident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

Clarification

The purpose of this item is to ensure that licensees examine their plants to determine what actions can be taken over the short term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident. The actions should be taken pending conclusions resulting in the long term degraded core rulemaking, which may result in a need to consider additional sources.

Any area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident is designated as a vital area. For purposes of this evaluation, vital areas and equipment are not necessarily the same vital areas or equipment defined in 10CFR Part 73.2 for security purposes. The security center is listed as an area to be considered as potentially vital, since access to this area may be necessary to take action to give access to other areas in the plant.

The control room, technical support center (TSC), sampling station, and sample analysis area must be included among those areas where access is considered vital after an accident. (Refer to Section III.A.1.2 of this report for discussion of the TSC and emergency operations facility.) The evaluation to determine the necessary vital areas should also include, but not be limited to, consideration of the post loss-of-coolant accident hydrogen control system, containment isolation reset control area, manual emergency core cooling system alignment area (if any), motor control centers, instrument panels, emergency power supplies, security center, and radwaste control panels. Dose rate determinations need not be done for these areas if they are determined not to be vital.

As a minimum, necessary modification must be sufficient to provide for vital system operation and for occupancy of the control room, TSC, sampling station, and sample analysis area.

In order to assure that personnel can perform necessary post-accident operations in the vital areas, the following guidance is to be used by licensees to evaluate the adequacy of radiation protection to the operators:

1. Source Term

The minimum radioactive source term should be equivalent to the source terms recommended in Regulatory Guides 1.3, 1.4, 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," and Standard Review Plan 15.6.5 with appropriate decay times based on plant design (i.e., assuming the radioactive decay that occurs before fission products can be transported to various systems).

(a) Liquid Containing Systems: 100 percent of the core equilibrium noble gas inventory, 50 percent of the core equilibrium halogen inventory, and 1 percent of all others are assumed to be mixed in the reactor coolant and liquids recirculated by residual heat removal, high pressure coolant injection, and low pressure coolant injection, or the equivalent of these systems. In determining the source term for recirculated, depressurized cooling water, assuming that the water contains no noble gases.

(b) Gas Containing Systems: 100 percent of the core equilibrium noble gas inventory and 25 percent of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For vapor containing lines connected to the primary system (e.g., boiling water reactor steam lines), the concentration of radioactivity shall be determined assuming the activity is contained in the vapor space in the Primary Coolant System.

2. <u>Systems Containing the Source</u>

Systems assumed in your analysis to contain high levels of radioactivity in a post accident situation should include, but not be limited to, containment, residual heat removal system, safety injection systems, chemical and volume control system, containment spray recirculation system, sample lines, gaseous radwaste systems, and standby gas treatment systems (or equivalent of these systems). If any of these systems or others that could contain high levels of radioactivity were excluded, you should explain why such systems were excluded. Radiation from leakage of systems located outside of containment need not be considered for this analysis. Leakage measurement and reduction is treated under Section III.D.1.1, "Integrity of Systems Outside Containment Likely to Contain Radioactive Material for PWRs and BWRs." Liquid waste systems need not be included in this analysis. Modifications to liquid waste systems will be considered after completion of Section III.D.1.4, "Radwaste System Design Features To Aid in Accident Recovery and Decontamination."

3. <u>Dose Rate Criteria</u>

The design dose rate for personnel in a vital area should be such that the guidelines of Criterion 19 of the General Design Criteria (GDC) will not be exceeded during the course of the accident. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel should not be in excess of 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. When determining the dose to an operator, care must be taken to determine the necessary occupancy times in a specific area. For example, areas requiring continuous occupancy will require much lower dose rates than areas where minimal occupancy is required. Therefore, allowable dose rates will be based upon expected occupancy, as well as the radioactive source terms and shielding. However, in order to provide a general design objective, we are providing the following dose rate criteria with alternatives to be documented on a case by case basis. The recommended dose rates are average rates in the area. Local hot spots may exceed the dose rate guidelines. These doses are design objectives and are not to be used to limit access in the event of an accident.

(a) Areas Requiring Continuous Occupancy: <15 mrem/hr (averaged over 30 days). These areas will require full-time occupancy during the course of the accident. The control room and onsite technical support center are areas where continuous occupancy will be required. The dose rate for these areas is based on the control room occupancy factors contained in Standard Review Plan 6.4.

(b) Areas Requiring Infrequent Access: GDC 19. These areas may require access on an irregular basis, not continuous occupancy. Shielding should be provided to allow access at a frequency and duration estimated by the licensee. The plant radiochemical/chemical analysis laboratory, radwaste panel, motor control center, instrumentation locations, and reactor coolant and containment gas sample stations are examples of sites where occupancy may be needed often, but not continuously.

4. Radiation Qualification of Safety-Related Equipment

The review of safety-related equipment which may be unduly degraded by radiation during post accident operation of this equipment relates to equipment inside and outside of the primary containment. Radiation source terms calculated to determine environmental qualification of safety-related equipment consider the following:

(a) Loss of coolant accident (LOCA) events which completely depressurize the primary system should consider releases of the source term (100 percent noble gases, 50 percent iodines, and 1 percent particulates) to the containment atmosphere.

(b) LOCA events in which the primary system may not depressurize should consider the source term (100 percent noble gases, 50 percent iodines, and 1 percent particulates) to remain in the primary coolant. This method is used to determine the qualification doses for equipment in close proximity to recirculating fluid systems inside and outside of containment. Non-LOCA events both inside and outside of containment should use 10 percent noble gases, 10 percent iodines, and 0 percent particulate as a source term. The following table summarizes these considerations:

Containment	LOCA Source Term (Noble Gas/Iodine/ Particulate)	Non-LOCA High Energy Line Break Source Term (Noble Gas/Iodine/ Particulate)
Outside	Percent (100/50/1) in Reactor Coolant System	Percent (10/10/0) in Reactor Coolant System
Inside	Larger of (100/50/1) in containment or (100/50/1) in Reactor Coolant System	(10/10/0) In Reactor Coolant System

Response

In compliance with the requirements stated in NUREG-0737, a post-accident shielding design and access review for HCGS has been completed. For details of this review, see Section 12.3.2.

The post-accident shielding is Q-listed (Item XIX.m of Table 3.2-1).

II.B.3 Post-Accident Sampling

Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," or 1.4 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactor" release of fission products. If the review indicates that personnel could not promptly and safely obtain samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases which indicate cladding failure and isotopes which indicate fuel melting. The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Clarification

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13, 1979, October 30, 1979, September 5, 1980 and October 31, 1980 clarification letters.

1. The applicant shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

2. The applicant shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above, quantification of the following.

    (a) Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and nonvolatile isotopes).

    (b) Hydrogen levels in the containment atmosphere.

(c) Dissolved gases (e.g., hydrogen), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

(d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

3. Reactor coolant and containment atmosphere sampling during post-accident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system) to be placed in operation in order to use the sampling system.

4. Pressurized reactor coolant samples are not required if the applicant can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or hydrogen gas in reactor coolant samples is considered adequate. Measuring the oxygen concentration is recommended, but is not mandatory.

5. The time for a chloride analysis to be performed is dependent upon two factors: 1) if the plant's coolant water is seawater or brackish water, and 2) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions, the applicant shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the applicant shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

6. The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding GDC 19 (i.e., 5 rem whole body, 75 rem extremities).

7. If inline monitoring is used for any sampling and analytical capability specified herein, the applicant shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

8. The applicant's radiological and chemical sample analysis capability shall include provisions to:

   (a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 1.3 or 1.4 and 1.7, "Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident." Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.

   (b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

9. Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe

radiological and chemical status of the reactor coolant systems.

10. In the design of the post-accident sampling and analysis capability, consideration should be given to the following items:

    (a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the reactor coolant system or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The post-accident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

    (b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high efficiency particulate air filters.

11. If gas chromatography is used for reactor coolant analysis, special provisions (e.g., pressure relief and purging) shall be provided to prevent high pressure argon from entering the reactor coolant.

12. Applicants should provide a description of the implementation of the position and clarification including pipe and instrumentation drawings, together with either 1) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or 2) copies of procedures for sample collection, sample transfer or transport,

and sample analysis, in accordance with the proposed review schedule but in no case less than 4 months prior to the issuance of an operating license. A post-implementation review will be performed.

Response

Provisions for post-accident sampling of reactor coolant and containment atmosphere are described in Section 9.3.2. The Post Accident Sampling System (PASS) is not Q-listed with the exception of the primary containment isolation and reactor coolant pressure boundary piping and valves (Item XVII.h of Table 3.2-1).

The HCGS design incorporates a radioactive gas and liquid sampling system designed by General Electric. Additionally, the radiological spectrum and chemical analysis capabilities will be reviewed prior to 5 percent power operation by an NRC site inspection to ensure that the appropriate analyses can be performed within the times specified in NUREG-0737.

Shielding requirements and source terms used are consistent with those used for the Design Review of Plant Shielding, discussed under Item II.B.2. The review to assure compliance of the radioactive gas and liquid sampling system for shielding and source term requirements has been completed and is described in Section 9.3.2.

II.B.4 Training for Mitigating Core Damage

Position

We require that the applicant develop a program to ensure that all operating personnel are trained in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. They must then implement the training program.

Clarification

STA and operating personnel from the Plant Manager through the operations chain to the licensed operators shall receive this training. The training program shall include the following topics:

1. Incore Instrumentation

   (a) Use of fixed or movable in-core detectors to determine extent of core damage and geometry changes.

   (b) Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

2. Excore Nuclear Instrumentation

   (a) Use of excore nuclear instrumentation for determination of void formation; void location basis for excore nuclear instrumentation response as a function of core temperatures and density changes.

3. Vital Instrumentation

   (a) Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual versus indicated level).

   (b) Alternative methods for measuring flows, pressures, levels, and temperatures.

      (1) Determination of pressurizer level if all level transmitters fail.

      (2) Determination of letdown flow with a clogged filter (low flow).

(3) Determination of other Reactor Coolant System parameters if the primary method of measurement has failed.

4. Primary Chemistry

(a) Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leaktight systems.

(b) Expected isotopic breakdown for core damage; for clad damage.

(c) Corrosion effects of extended immersion in primary water; time to failure.

5. Radiation Monitoring

(a) Response of process and area monitors to severe damage; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (overranged detector); expected accuracy of detectors at different locations; use of detectors to determine extent of core damage.

(b) Methods of determining dose rate inside containment from measurements taken outside containment.

6. Gas Generation

(a) Methods of hydrogen generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of noncondensibles.

(b) Hydrogen flammability and explosive limit; sources of oxygen in containment or Reactor Coolant System.

Managers and technicians in the instrumentation and control, health physics, and chemistry departments shall receive training commensurate with their responsibilities.

Response

A program for training of all plant operations staff in mitigating core damage has been implemented.

II.D.1 Relief and Safety Valve Test Requirements

Position

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the Reactor Coolant System relief and safety valves under expected operating conditions for design basis transients and accidents.

Clarification

Licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor coolant system relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

1. Performance Testing of Relief and Safety Valves - The following information must be provided in report form:

(a) Evidence supported by test of safety and relief valve functionality for expected operating and accident (non-ATWS) conditions must be provided to NRC. The testing should demonstrate that the valves will open and reclose under the expected flow conditions.

(b) Since it is not planned to test all valves on all plants, each licensee must submit to NRC a correlation or other evidence to substantiate that the valves tested in the EPRI (Electric Power Research Institute) or other generic test program demonstrate the functionality of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the FSAR. The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for, if it is different from the generic test loop piping.

(c) Test data including criteria for success and failure of valves tested must be provided for NRC staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

2. Qualification of PWR Block Valves-Although not specifically listed as a short term lessons learned requirement in NUREG-0578, qualification of PWR block valves is required by the NRC Task Action Plan NUREG-0660 under task Item II.D.1. It is the understanding of the NRC that testing of several commonly used block valve designs is already included in the generic EPRI PWR safety and relief valve testing program to be completed by July 1, 1981. By means of this letter, NRC is establishing July 1, 1982 as the date for verification of block valve functionality. By July 1, 1982, each PWR licensee, for plants so equipped, should provide evidence supported by test that the block or isolation valves between the pressurizer and

each power operated relief valve can be operated, closed, and opened for all fluid conditions expected under operating and accident conditions.

3. ATWS Testing-Although ATWS testing need not be completed by July 1, 1981, the test facility should be designed to accommodate ATWS conditions of approximately 3200 to 3500 pounds per square inch (Service Level C pressure limit) and 700 degrees Fahrenheit with sufficient capacity to enable testing of relief and safety valves of the size and type used on operating pressurized water reactors.

Response

PSE&G is participating in the BWROG program to test safety/relief valves. Wyle Laboratories in Huntsville, Alabama, was contracted to design and build a test facility. The facility is capable of high and low pressure valve tests.

Documentation of the BWROG testing program was sent to the NRC on September 17, 1980, by a letter from D.B. Waters to R.N. Vollmer. A summary of this document is provided below.

An engineering evaluation was made to identify the expected operating conditions for safety/relief valves (SRVs) during design basis transients and accidents. This evaluation indicates the safety/relief valves may be required to pass low pressure liquid as a result of the alternate shutdown cooling mode described in Section 15.2.9. No other significantly probable event even combined with a single active failure or single operator error that would require SRV testing was identified in this report. Therefore, a test program was developed to demonstrate the SRV capabilities as may be necessary during the alternate shutdown mode.

The generic test program has been completed and the results were documented to the NRC in October, 1981. The results showed that for all the SRVs tested, the valves operated properly for the test conditions. Also the loads for the water discharge were significantly less than the design basis steam loads. The NRC has accepted the generic SRV test program and has requested that individual applicants justify the applicability of the test data to their plants. An analysis of the applicability of the testing program for HCGS valves was submitted to the NRC on October 25, 1983 by a letter from R.L. Mittl to A. Schwencer.

II.D.3 Relief and Safety Valve Position Indication

Position

Reactor Coolant System relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe.

Clarification

1. The basic requirement is to provide the operator with unambiguous indications of valve position (open or closed) so that appropriate operator actions can be taken.

2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

3. The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single channel direct indication, powered from a vital instrument bus, may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis of an action.

4. The valve position indication should be seismically qualified consistent with the component or system to which it is attached.

5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with Commission Order of May 23, 1980 (CLI-80-21).

6. It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

   (a) the use of this information by an operator during both normal and abnormal plant conditions,

   (b) integration into emergency procedures,

   (c) integration into operator training, and

   (d) other alarms during emergency and need for prioritization of alarms.

Response

The HCGS design includes an Acoustic Monitoring System that meets the requirements of NUREG-0737 and Regulatory Guide 1.97, Revision 2. See Section 7.5.1.3.6 for a description of the Safety/ Relief Valve Position Indication System. The SRV position indication system is not Q-listed (Item XV.d.5 of Table 3.2-1).

II.E.1.1 Auxiliary Feedwater System Evaluation

Response

These requirements are not applicable to BWRs.

II.E 1.2 Auxiliary Feedwater System Initiation and Flow

Response

This requirement is not applicable to BWRs.

II.E.3.1 Emergency Power for Pressurizer Heaters

Response

This not requirement is applicable to BWRs.

II.E.4.1 Dedicated Hydrogen Control Penetrations

Position

Plants using external recombiners or purge systems for post accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single failure requirements of GDC 54 and 56 and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

Clarification

1. An acceptable alternative to the dedicated penetration is a combined design that is single failure proof for containment isolation purposes and single failure proof for operation of the recombiner or purge system.

2. The dedicated penetration or the combined single failure proof alternative shall be sized such that the flow requirements for the use of the recombiner or purge system are satisfied. The design shall be based on 10CFR50.44 requirements.

3. Components furnished to satisfy this requirement shall be safety grade.

4. Licensees that rely on purge systems as the primary means for controlling combustible gases following a loss-of-coolant accident should be aware of the positions taken in SECY-80-399, "Proposed Interim Amendments to 10CFR Part 50 Related to Hydrogen Control and Certain Degraded Core Considerations." This proposed rule, published in the Federal Register on October 2, 1980, would require plants that do not now have recombiners to have the capacity to install external recombiners by January 1, 1982. (Installed internal recombiners are an acceptable alternative to the above.)

5. Containment Atmosphere Dilution (CAD) Systems are considered to be purge systems for the purpose of implementing the requirements of this TMI Task Action item.

Response

The safety-related containment hydrogen recombiner system, described in Section 6.2.5, is used for beyond design basis accident combustible gas control. The containment penetrations associated with the hydrogen recombiner system are a combined design as described in clarification 1 above. This design is single failure proof for containment isolation purposes during system operation and single failure proof for operation of the recombiner or purge system.

The piping is sized such that the flow requirements for the use of the recombiner are satisfied for the full range of possible containment pressures during the time period when the recombiner might be required to operate.

HCGS is provided with permanently installed recombiners that are remotely operated from the control room. Personnel access to this equipment after an accident is therefore not required.

The shielding requirements associated with recombiner have been evaluated as art of the Design Review for Plant Shielding, which is discussed under Item II.B.2.

The dedicated hydrogen control penetrations are Q-listed (Item V.d.5.g and h of Table 3.2-1).

II.E.4.2 Containment Isolation Dependability

Position

1. Containment isolation system designs shall comply with the recommendations of Standard Review Plan Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

2. All plant personnel shall give careful consideration of the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.

3. All non-essential systems shall be automatically isolated by the containment isolation signal.

4. The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

5. The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

6. Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4, Item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days.

7. Containment purge and vent isolation valves must close on a high radiation signal.

Clarification

1. The reference to SRP 6.2.4 in position 1 is only to the diversity requirements set forth in that document.

2. For post accident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet requirements of General Design Criteria 54, 55, 56, and 57, as clarified by Standard Review Plan, Section 6.2.4. Isolation must be performed automatically (i.e., no credit can be given for operator action). Manual valves must be sealed closed, as defined by Standard Review Plan, Section 6.2.4 to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

3. Revision 2 to Regulatory Guide 1.141 will contain guidance on the classification of essential versus nonessential systems and is due to be issued by June 1981. Requirements for operating plants to review their list of essential and nonessential systems will be issued in conjunction with this guide including an appropriate time schedule for completion.

4. Administrative provisions to close all isolation valves manually before resetting the isolation signals is not an acceptable method of meeting position 4.

5. Ganged reopening of containment isolation valves is not acceptable. Reopening of isolation valves must be performed on a valve by valve basis, or on a line by line basis, provided that electrical independence and other single failure criteria continue to be satisfied.

6. The containment pressure history during normal operation should be used as a basis for arriving at an appropriate minimum pressure setpoint for initiating containment isolation. The pressure setpoint selected should be far enough above the maximum observed (or expected) pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuations due to the accuracy of the pressure sensor. A margin of 1 psi above the maximum expected containment pressure should be adequate to account for instrument error. Any proposed values greater than 1 psi will require detailed justification. Applicants for an operating license and operating plant licensees that have operated less than one year should use pressure history data from similar plants that have operated more than one year, if possible, to arrive at a minimum containment setpoint pressure.

7. Sealed closed purge isolation valves shall be under administrative control to assure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. Checking the valve position light in the control room is an adequate method for verifying every 24 hours that the purge valves are closed.

Response

Essential systems are those critical to the mitigation of the consequences of a LOCA. Also identified as essential are those systems that could be useful, although not critical, in mitigating an accident that results in containment isolation. Essential systems are not automatically isolated by accident signals, except for the containment heat removal and containment hydrogen control systems that are not required immediately for accident mitigation. Containment isolation valves are Q-listed (See Table 3.2-1 under applicable system).

Nonessential systems are those that are not required or used in the mitigation of an accident that results in containment isolation. All nonessential systems are automatically isolated by the containment isolation signal, with the exception of the systems discussed below:

1. Reactor Water Cleanup (RWCU) System Return - Automatic isolation of Valve AE-V021 (AE-HV-F039) is not provided because there are two check valves on either side of the containment boundary providing primary containment isolation for the feedwater system. These valves will provide immediate isolation without actuation of the motor operated valve by an isolation signal. Valve AE-V021 is a motor operated check valve that closes on backflow and is capable of being manually closed from the main control room.

2. Bypass Lines Around the Testable Check Valves on the RHR and Core Spray System - Although the check valves perform containment isolation functions, they are not containment isolation valves in accordance with the "other defined basis" provisions of 10CFR50, Appendix J. The valves in the 1-inch bypass lines are not automatically isolated because they are normally closed, fail-closed valves that are only operated to equalize pressures to permit the testing of the check valves. The valves are opened by an operator holding a momentary pushbutton switch in the open position. Release of the switch by the operator will return the valves to the closed position.

3. Warmup Lines Around the Inboard HPCI and RCIC Steam Line Isolation Valves - Automatic isolation of these valves is not provided because they are in the essential systems and are not required to perform a containment isolation function when the RCIC and HPCI systems are in operation.

4. Post-Accident Sampling System - Automatic isolation of the post-accident sampling lines is not provided because the penetrations are designed to be a sealed closed system. Administrative procedures prevent the containment isolation valves from being inadvertently opened by ensuring that power is not supplied to the valves until the system is required to operate.

Reopening of primary containment isolation valves requires deliberate operator action on a valve by valve basis. Valves with manual override capabilities are identified in Table 6.2-16. Essential and nonessential systems are identified in Table 6.2-16.

Diverse parameters are sensed for the initiation of automatic isolation of nonessential systems penetrating primary containment. See Section 6.2.4 for a discussion of containment isolation signal sensed parameter diversity.

As required for post-accident situations, each nonessential penetration, except instrument lines, has two isolation barriers in series that meet the requirements of GDC 54, 55, 56, or 57, as clarified by SRP Section 6.2.4. Isolation is automatic with no credit taken for operator action. All manual valves are sealed closed so as to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration receives independent isolation signals, derived from diverse parameters.

The design of the controls for automatic containment isolation are such that the resetting of the isolation signals will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves will require deliberate operator action on a valve by valve basis. Ganged reopening of containment isolation valves is not used.

An exception to this response is the HPCI Torus Suction Isolation Valve, 1BJHV-FO42. This valve will automatically reopen upon the resetting of a HPCI System Isolation signal if an automatic open signal is present. This configuration is discussed in UFSAR Section 6.2.4.3.2.9.

The primary containment isolation logic setpoint pressure is 1.68 psig. This pressure is far enough above the maximum expected pressure inside containment during normal operation that inadvertent containment isolation does not occur during normal operation from instrument drift fluctuations due to the accuracy of the pressure sensor.

The 6-, 24-, and 26-inch containment purge and vent butterfly valves are under administrative control. As discussed in Section 6.2.5.2, the 24- and 26-inch inboard vent valves (1-GS-HV-4952 and -4964), in conjunction with the 2-inch air operated globe valves (1-GS-HV-4951 and -4963), are opened to vent as required for thermal expansion and oxygen control. The purge supply and exhaust valves may be opened at other times as permitted by Technical Specifications.

II.F.1 <u>Accident Monitoring Instrumentation</u>

Attachment 1, <u>Noble Gas Effluent Monitor</u>

<u>Position</u>

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

1. Noble gas effluent monitors with an upper range capacity of 10^5 μ/Ci/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

2. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (as low as reasonably achievable (ALARA)) concentrations to a maximum of 10^5 μ/Ci/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

1. The use of this information by an operator during both normal and abnormal plant conditions;

2. Integration into emergency procedures;

3. Integration into operator training; and

4. Other alarms during emergency and need for prioritization of alarms.

Clarification

NUREG-0578, Section 2.1.8b provided the basic requirements for this item. Letters dated September 27 and November 9, 1979, provided clarification and NUREG-0660, Item II.F.1 provided the action plan for additional accident monitoring instrumentation by noble gas effluent radiological monitor requirements. Additional clarification was provided by letters dated September 5 and October 31, 1980.

By summary clarification, the following guidelines were established:

1. Applicants shall provide continuous monitoring of high-level post accident releases of radioactive noble gases from the plant. Gaseous effluent monitors shall meet requirements specified in the enclosed Table II.F.1-1. Typical plant effluent pathways to be monitored are also given in the table.

2. The monitors shall be capable of functioning both during and following an accident. System designs shall accommodate a design basis release and then be capable of following decreasing concentrations of noble gases.

3. Offline monitors are not required for the pressurized water reactor secondary side main steam safety valve and dump valve discharge lines. For this application, externally mounted monitors viewing the main steam line upstream of the valves are acceptable with procedures to correct for the low energy gammas the external monitors would not detect. Isotopic identification is not required.

4. Instrumentation ranges shall overlap to cover the entire range of effluents from normal (ALARA) through accident conditions.

The design description shall include the following information:

(a) System description, including:

(1) instrumentation to be used, including range or sensitivity, energy dependence or response, calibration frequency and technique, and vendor's model number, if applicable.

(2) monitoring locations (or points of sampling), including description of methods used to assure representative measurements and background correction.

(3) location of instrument readout(s) and method of recording, including description of the method or procedure for transmitting or disseminating the information or data.

(4) assurance of the capability to obtain readings at least every 15 minutes during and following an accident.

(5) the source of power to be used.

(b) Description of procedures or calculational methods to be used for converting instrument readings to release rates per unit time, based on exhaust air flow and considering radionuclide spectrum distribution as a function of time after shutdown.

(5.) Applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either 1) a description of procedures for system operation and calibration, or 2) copies of procedures for system operation and calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with the proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A post implementation review will be performed.

Until final implementation on January 1, 1982, all operating reactors must provide an interim method for quantifying high level releases which meet the requirements of the enclosed Table II.F.1-2. This method is to serve only as a provisional fix until the accident monitoring instrumentation is installed, calibrated, tested and approved by January 1, 1982. Methods are to be developed to quantify release rates up to 10,000 Ci/sec for noble gases from all potential release points and any other areas that communicate directly with systems which may contain primary coolant or containment gases. Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such that measurements of individual sources which contribute to the common release point may not be necessary. For noble gases, an acceptable method of meeting the intent of this requirement is to modify the existing monitoring system, such that portable high range survey instruments set in shielded collimators "see" small sections of the sampling lines. The applicant shall provide the following information on its method to quantify gaseous releases of radioactivity from the plant during an accident.

(a) An interim system/method description for noble gas effluents, including:

(1) instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique.

(2) monitoring/sampling locations, including methods to assure representative measurements and background radiation correction.

(3) a description of method to be employed to facilitate access to radiation readings. For January 1, 1981, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on 4., below.

(4) capability to obtain radiation readings at least every 15 minutes during an accident.

(5) source of power to be used. If normal alternating current power is used, an alternate backup power supply should be provided. If direct current power is used, the source should be capable of providing continuous readout for 7 consecutive days.

(b) Procedures for conducting all aspects of the measurement/analysis, including:

(1) procedures for minimizing occupational exposures.

(2) calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown.

(3) procedures for dissemination of information.

(4) procedures for calibration.

TABLE II.F.1-1

HIGH-RANGE NOBLE GAS EFFLUENT MONITORS

REQUIREMENT - Capability to detect and measure concentrations of noble fission products in plant gaseous effluents during and following an accident. All potential accident release paths shall be monitored.

PURPOSE - To provide the plant operator and emergency planning agencies with information on plant releases of noble gases during and following an accident.

TABLE II.F.1-1 (Cont)

DESIGN BASIS MAXIMUM RANGE

Design range values may be expressed in Xe-133 equivalent values for monitors employing gamma radiation detectors or in microcuries per cubic centimeter (μCi/cc) of air at standard temperature and pressure (STP) for monitors employing beta radiation detector (Note: 1R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrations with a higher energy source are acceptable. The decay of radionuclide noble gases after an accident (i.e., the distribution of noble gas changes) should be taken into account.

10^5 μCi/cc

- Undiluted containment exhaust gases (e.g., pressurized water reactor, reactor building purge, boiling water reactor drywell purge through the standby gas treatment system).
- Undiluted pressurized water reactor condenser air removal system exhaust.

10^4 μCi/cc

- Boiling water reactor, Reactor Building (secondary containment) exhaust air.
- Pressurized water reactor secondary containment exhaust air.

10^3 μCi/cc

- Buildings with systems containing primary coolant or primary coolant off-gases (e.g., pressurized water reactor Auxiliary Buildings, boiling water reactor Turbine Buildings).
- Pressurized water reactor steam safety valve discharge, atmospheric steam dump valve discharge.

TABLE II.F.1-1 (Cont)

10^2 µCi/cc	-	Other release points (e.g., Radwaste Buildings, fuel handling/storage buildings).
REDUNDANCY	-	Not required; monitoring the final release point of several discharge inputs is acceptable.
SPECIFICATIONS	-	(None) Sampling design criteria per ANSI N13.1.
POWER SUPPLY	-	Vital instrument bus or dependable backup power supply to normal alternating current.
CALIBRATION	-	Calibrate monitors using gamma detectors to Xe-133 equivalent (1R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrate monitors using beta detectors to Sr-90 or similar long-lived beta isotope of at least 0.2 MeV.
DISPLAY	-	Continuous and recording as equivalent Xe-133 concentrations or µCi/cc of actual noble gases.
QUALIFICATION	-	The instruments shall provide sufficiently accurate responses to perform the intended function in the environment to which they will be exposed during accidents.
DESIGN CONSIDERATIONS	-	Offline monitoring is acceptable for all ranges of noble gas concentrations.
	-	Inline (induct) sensors are acceptable for 10^2 µCi/cc to 10^5 µCi/cc noble gases. For less than 10^2 µCi/cc, offline monitoring is recommended.

TABLE II.F.1-1 (Cont)

- Upstream filtration (prefiltering to remove radioactive iodines and particulates) is not required; however, design should consider all alternatives with respect to capability to monitor effluents following an accident.

- For external mounted monitors (e.g., pressurized water reactor main steam line), the thickness of the pipe should be taken into account in accounting for low energy gamma radiation.

Applicants are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off scale.

Examples of major elements of a highly radioactive effluent release special procedure (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.

- Provide shielding to minimize background interference.

- Use of an installed monitor (preferable) or dedicated portable monitoring (acceptable) to measure the radiation.

- Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

Response

All Reactor Building vent noble gas effluent monitors, described in Section 11.5, meet the requirements of Revision 2 of Regulatory Guide 1.97.

ATTACHMENT 2, Sampling and Analysis of Plant Effluents

Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near term.

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

1. The use of this information by an operator during both normal and abnormal plant conditions.

2. Integration into emergency procedures.

3. Integration into operator training.

4. Other alarms during emergency and need for prioritization of alarms.

Clarification

NUREG-0578, Section 3.1.8b provided the basic requirements for this item. Letters dated September 27 and November 9, 1979, provided clarification, however, NUREG-0660 inadvertently omitted this requirement on the action plan for additional accident-monitoring instrumentation by sampling and analysis of plant effluents. Additional clarification was provided by letters dated September 5 and October 31, 1980.

By summary clarification, the following guidelines were established:

1. Applicants shall provide continuous sampling of plant gaseous effluent for post accident releases of radioactive iodines and particulates to meet the requirements of the enclosed Table II.F.1-3. Applicants shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

2. The shielding design basis is given in Table II.F.1-3. The sampling system design shall be such that plant personnel could remove samples, replace sampling media and transport the samples to the onsite analysis facility with radiation exposures that are not in excess of the GDC 19 of 5 rem whole body exposure and 75 rem to the extremities during the duration of the accident.

3. The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same velocity) with expected induct or instack air velocities. For accident conditions,

sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of ~ 20 percent. Further departure from the isokinetic condition need not be considered in design. Corrections for an isokinetic sampling conditions, as provided in Appendix C of ANSI 13.1-1969 may be considered on an ad hoc basis.

4. effluent steams which may contain air with entrained water, e.g., air ejector discharge, shall have provisions to ensure that the adsorber is not degraded while providing a representative sample, e.g., heaters.

5. License applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either 1) a description of procedures for system operation and calibration, or 2) copies of procedures for system operation and calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A post implementation review will be performed.

TABLE II.F.1-3

SAMPLING AND ANALYSIS OR MEASUREMENT OF HIGH-RANGE RADIOIODINE AND PARTICULATE EFFLUENTS IN GASEOUS EFFLUENT STREAMS

EQUIPMENT - Capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluents during and following an accident. The capability to sample and analyze for radioiodine and particulate effluents is not required for pressurized water reactor secondary main steam safety valve and dump valve discharge lines.

PURPOSE - To determine quantitative release of radioiodines and particulates for dose calculation and assessment.

DESIGN BASIS SHIELDING ENVELOPE - 10^2 μCi/cc of gaseous radioiodine and particulates, deposited on sampling media; 30 minutes sampling time, average gamma energy (E) of 0.5 MeV.

SAMPLING MEDIA

- Iodine > 90 percent effective adsorption for all forms of gaseous iodine.
- Particulates > 90 percent effective retention for 0.3 micron (μ) diameter particles.

SAMPLING CONSIDERATIONS

- Representative sampling per ANSI N13.1-1969.

- Entrained moisture in effluent steam should not degrade adsorber.

- Continuous collection required whenever exhaust flow occurs.

- Provisions for limiting occupational dose to personnel incorporated in sampling systems, in sample handling and transport, and in analysis of samples.

ANALYSIS

- Design of analytical facilities and preparation of analytical procedures shall consider the design basis sample.

- Highly radioactive samples may not be compatible with generally accepted analytical procedures; in such cases, measurement of emissive gamma radiations and the use of shielding and distance factors should be considered in design.

Response

The isokinetic effluent iodine and particulate filters and radiogas monitors for the North Plant Vent, South Plant Vent, and FRVS radiation monitoring systems on the post-accident effluent stream are described in Section 11.5. The inlet sample lines are heat-traced as indicated by Plant Drawing M-26-1.

ATTACHMENT 3, Containment High Range Radiation Monitor

Position

In containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

Clarification

1. Provide two radiation monitor systems in containment which are documented to meet the requirements of Table II.F.1-4.

2. The specification of 10^8 rad/hr in the above position was based on a calculation of post-accident containment radiation levels that include both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA (loss-of-coolant accident) containment environments but gamma-sensitive instruments can be so qualified. In order to follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979 letter to provide for a photon-only measurement with an upper range of 10^7 R/hr.

3. The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a Reactor Building dome is not recommended because of potential maintenance difficulties.

4. For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

5. The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table II.F.1-4. Monitors that use thick shielding to increase the upper range will underestimate post-accident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gamma and are not acceptable.

TABLE II.F.1-4

CONTAINMENT HIGH-RANGE RADIATION MONITOR

REQUIREMENT	-	The capability to detect and measure the radiation level within the reactor containment during and following an accident.
RANGE	-	1 R/hr to 10^7 R/hr (gamma only)
RESPONSE	-	60 keV to 3 MeV photons (with linear energy response ~ 20 percent for photons of 0.1 MeV to 3 MeV). Instruments must be accurate enough to provide usable information.
REDUNDANT	-	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).

TABLE II.F.1-4 (Cont)

DESIGN AND QUALIFICATION	-	Category 1 instruments as described in Appendix A except as listed below.
SPECIAL CALIBRATION	-	In situ calibration by electronic signal substitution is acceptable for all range decades above 10 R/hr. In situ calibration for at least one decade below 10 R/hr shall be by means of calibrated radiation source. The original laboratory calibration is not an acceptable position due to the possible differences after in situ installation. For high range calibration, no adequate sources exist, so an alternate was provided.
SPECIAL ENVIRONMENTAL QUALIFICATIONS	-	Calibrate and type-test representative specimens of detectors at sufficient points to demonstrate linearity through all scales up to 10^6 R/hr. Prior to initial use, certify calibration of each detector for at least one point per decade of range between 1 R/hr and 10^3 R/hr.

Response

The in-containment radiation monitors described in Section 11.5 have a maximum range of 1 to 10^8 R/hr (gamma) and are physically separated. They are designed and qualified to function in an accident environment.

Attachment 4, Containment Pressure Monitor

Position

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

Clarification

1. Design and qualification criteria are outlined in Appendix B of NUREG-0737.

2. Measurement and indication capability shall extend to 5 pounds per square inch absolute for sub-atmospheric containments.

3. Two or more instruments may be used to meet requirements. However, instruments that need to be switched from one scale to another scale to meet the range requirements are not acceptable.

4. Continuous display and recording of the containment pressure over the specified range in the control room is required.

5. The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

Response

The existing containment pressure instrumentation is identified in Section 7.5.1 and Table 7.5-1.

Attachment 5, Containment Water Level Monitor

Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for pressurized water reactors (PWRs) and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for boiling water reactors (BWRs) and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

Clarification

1. The containment wide range water level indication channels shall meet the design and qualification criteria as outlined in Appendixes B and C. The narrow range channel shall meet the requirements of Regulatory Guide 1.89.

2. The measurement capability of 600,000 gallons is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement based on the available water supply capability at their plant.

3. Narrow range water level monitors are required for all sizes of sumps but are not required in those plants that do not contain sumps inside the containment.

4. For BWR pressure-suppression containments, the Emergency Core Cooling System (ECCS) suction line inlets may be used as a starting reference point for the narrow range and wide range water level monitors, instead of the bottom of the suppression pool.

5. The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

Response

The existing water level instrumentation, described in Section 7.5.1 conforms to the BWROG position on NRC Regulatory Guide 1.97, Revision 2.

Attachment 6, Containment Hydrogen Monitor

Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10 percent hydrogen concentration under both positive and negative ambient pressure.

Clarification

1. Design and qualification criteria are outlined in Appendix B.

2. The continuous indication of hydrogen concentration is not required during normal operation.

   If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection.

3. The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.

Response

The hydrogen monitoring instrumentation is identified in Section 7.3. Plant Drawing J-57-0 identifies the containment atmosphere control system's design operations.

II.F.2 Instrumentation for Detection of Inadequate Core Cooling

Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy to interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

Clarification

1. Design of new instrumentation should provide an unambiguous indication of ICC. This may require new measurements or a synthesis of existing measurements which meet design criteria (Item 7).

2. The evaluation is to include reactor water level indication.

3. Licensees and applicants are required to provide the necessary design analysis to support the proposed final instrumentation system for inadequate core cooling and to evaluate the merits of various instruments to monitor water level and to monitor other parameters indicative of core cooling conditions.

4. The indication of ICC must be unambiguous in that it should have the following properties:

   (a) It must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high void fraction pumped flow as well as stagnant boiloff).

   (b) It must not erroneously indicate ICC because of the presence of an unrelated phenomenon.

5. The indication must give advanced warning of the approach of ICC.

6. The indication must cover the full range from normal operation to complete core uncover. For example, water level instrumentation may be chosen to provide advanced warning of two phase level drop to the top of the core and could be supplemented by other indicators such as incore and core-exit thermocouples provided that the indicated temperatures can be correlated to provide indication of the existence of ICC and to infer the extent of core uncover. Alternatively, full range level instrumentation to the bottom of the core may be employed in conjunction with other diverse indicators such as core exit thermocouples to preclude misinterpretation due to any inherent deficiencies or inaccuracies in the measurement system selected.

7. All instrumentation in the final ICC system must be evaluated for conformance to Appendix B of NUREG-0737, "Clarification of TMI Action Plan Requirements," as clarified or modified by the provisions of Items 8 and 9 that follow. This is a new requirement.

8. If a computer is provided to process liquid level signals for display, seismic qualification is not required for the computer and associated hardware beyond the isolator or input buffer at

a location accessible for maintenance following an accident. The single failure criteria of Item 2, Appendix B, need not apply to the channel beyond the isolation device if it is designed to provide 99 percent availability with respect to functional capability for liquid level display. The display and associated hardware beyond the isolation device need not be Class 1E, but should be energized from a high reliability power source which is battery backed. The quality assurance provisions cited in Appendix B, Item 5, need not apply to this portion of the instrumentation system. This is a new requirement.

9. In-core thermocouples located at the core exit or at discrete axial levels of the ICC monitoring system and which are part of the monitoring system should be evaluated for conformity with Attachment 1, "Design and Qualification Criteria for PWR Incore Thermocouples," which is a new requirement.

10. The types and locations of displays and alarms should be determined by performing a human factors analysis taking into consideration:

    (a) The use of this information by an operator during both normal and abnormal plant conditions

    (b) Integration into emergency procedures

    (c) Integration into operator training

    (d) Other alarms during emergency and need for prioritization of alarms

Response

The HCGS design does not include the use of in-core thermocouples for detection of inadequate core cooling. PSE&G endorses the position of the BWR Owner's Group as outlined in the S. Levy Inc. Reports (SLI 8218 & SLI 8211) that there is no technical basis for requiring in-core thermocouples in addition to the existing water level instrumentation.

HCGS incorporates the BWR Owner's Group recommendation to use analog equipment in place of mechanical level indication equipment. HCGS has also rerouted instrument lines for two channels of level monitoring instrumentation to minimize the vertical instrument line drop inside the drywell. This reduces the amount of instrument line that would be exposed to high drywell temperatures in the event of an accident or loss of drywell cooling. By doing this, the possibility of losing level indication has been significantly reduced. The following discussion describes the reasoning behind the decision to reroute these instrument lines.

An evaluation of the effects of high temperatures on reference legs of water level measuring instruments subsequent to High Energy Line Breaks (HELB) is divided into two parts: 1) the effects of temperature alone, and 2) the effects of flashing/boiloff.

High Temperature Effects (without flashing/boiloff)

An increase in the temperature of the drywell will cause a heatup of the fluid in the instrument sensing lines, contributing to sensor error. The HCGS instrument sensing line design reduces this error by routing the variable leg and the reference leg lines with equivalent elevation drops in the drywell. The only exceptions to this design are the Upset Range transmitters' reference leg sensing lines. Physical configuration prevents equivalent routing of these lines. However, these transmitters are used exclusively for indication and will not present any challenges to plant safety.

A high drywell temperature alarm is computer generated from isolated outputs of Class 1E temperature transmitters. Class 1E temperature recorders located in the main control room provide a continuous display of drywell temperature.

Flashing/Boiloff Effects

The effect of flashing/boiloff of the instrument line reference leg is to cause the level instruments to indicate erroneously high levels. The amount of error is directly related to the drop in elevation of piping physically located within the drywell and subject to flashing.

HCGS has rerouted two channels of reactor pressure vessel (RPV) level instrumentation sensing lines to provide a maximum 3-ft elevation drop in the drywell (maximum 1-ft drop for the reference legs). A worst case analysis of the effects of boiloff of that portion of the sensing line inside the drywell, indicates the instruments using the rerouted lines will indicate a level that is 1.3 ft higher than actual. During and after a HELB the operator is required to maintain RPV level within the normal operating range, 18 ft above the top of active fuel. The 1.3 ft error is negligible with respect to the operating requirements.

Transmitters used for post accident monitoring use the rerouted lines. Therefore, the wide, narrow, and fuel zone range recorders and indicators will provide an unambiguous display of level even after partial flashing of the reference legs.

As a result of a HELB in containment, the drywell temperature may reach a maximum of 340°F. Flashing/boiloff of the sensing lines may occur when the RPV pressure is less than 118 psia when the drywell temperature is 340°F. At the 118 psia RPV pressure the High Pressure Coolant Injection (HPCI) system and the Automatic Depressurization System (ADS) are not required.

In response to a HELB of a large or intermediate sized line (see Figure 15.9-43) Low Pressure Coolant Injection (LPCI) and core spray are initiated by low water level 1 (L1) or high drywell pressure signals. For these postulated events, HPCI and ADS are not required.

Two different response paths must be considered for a small break accident (SBA).

The first response path considers a SBA with HPCI available. The Emergency Core Cooling System (ECCS) response to a SBA is outlined in FSAR Chapter 15 in response to Event 42 (Figure 15.9-43). Core spray and LPCI are initiated by high drywell pressure. HPCI is initiated on receipt of a low level 2 or high drywell pressure signal. HPCI continues to operate until the reactor vessel pressure is below the pressure at which LPCI or core spray operation can maintain core cooling. LPCI and core spray are designed to begin injecting water into the RPV when the differential pressure between the RPV and the suppression chamber is approximately 300 psid per design requirements (see FSAR Chapter 6.3).

The second response path considers a HPCI line SBA that incapacitates HPCI. Accident mitigation requires the actuation of the Automatic Depressurization System (ADS), LPCI, and core spray. LPCI and core spray are initiated on high drywell pressure or a L1 signal. ADS is initiated by a L1 and high drywell pressure and a level 3 permissive signal when low pressure ECCS pumps are running. At the point flashing could occur, the RPV pressure will be low enough that ADS will not be required; before that point level signals/actuations will remain accurate.

In the event of any credible HELB inside containment, the capability of the ECCS to mitigate the accident is not compromised by high drywell temperature or flashing of the RPV level instrumentation line reference legs.

II.G.1 Power Supplies for Pressurizer Relief Valves, Block Valves and Level Indicators

Response

This item is not applicable to BWRs.

II.K.1 IE Bulletins on Measures to Mitigate Small Break LOCAs and Loss of Feedwater Accidents

II.K.1.5 Assurance of Proper Engineered Safety Features Functioning

Position

Review all safety-related valve positions, positioning requirements, and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also, review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during operational modes.

Response

This requirement has been incorporated into the appropriate NBU administrative procedure(s). Refer to the response to position I.C.6 for supplementary information.

II.K.1.10

Position

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known.

Response

This requirement has been incorporated into the appropriate NBU administrative procedure(s).

II.K.1.17

Position

Trip pressurizer level bistable so that low pressure (rather than pressurizer low pressure and pressurizer low-level coincidence) will initiate safety injection.

Response

This requirement is not applicable to HCGS, which has a GE BWR.

II.K.1.20

Position

Provide procedures and training to operators for prompt manual reactor trip for loss of feedwater, turbine trip, main steamline isolation valve closure, loss of offsite power, loss of steam generator level, and low pressurizer level.

Response

This requirement is not applicable to HCGS.

II.K.1.21

Position

Provide automatic safety-grade anticipatory reactor trip for loss of feedwater, turbine trip, or significant decrease in steam generator level.

Response

This requirement is not applicable to HCGS.

II.K.1.22 Proper Functioning of Heat Removal Systems

Position

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., reactor core isolation cooling) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

Response

HCGS endorses the operator action scenario described in the BWROG position. See Section 5.4.6 and 5.4.7 for discussion of the automatic and manual actions necessary for the proper functioning of heat removal systems when the Main Feedwater System is not available.

II.K.1.23 Reactor Vessel Water Level Indication

Position

Describe all uses and types of reactor vessel level indication for both automatic and manual initiation of safety systems. Describe other instrumentation that might give the operator the same information on plant status.

Response

All uses and types of reactor vessel water level indication for both automatic and manual initiation of safety systems are shown on Plant Drawing M-42-1, Nuclear Boiler Instrumentation P&ID. With all other conditions normal, other instrumentation that might give the control room operator the same information on plant status as low reactor water level are:

1. Increase in reactor water temperature at recirculation pump suction
2. Decrease in reactor pressure
3. Increase in drywell sump level.

II.K.2 Commission Orders on Babcock & Wilcox Plants

Response

These requirements are not applicable to HCGS.

II.K.3 Final Recommendations of B&O Task Force

II.K.3.1 Installation and Testing of Automatic PORV Isolation System

Response

This requirement is not applicable to HCGS.

II.K.3.2 Report on Overall Safety Effect of PORV Isolation System

Response

This requirement is not applicable to HCGS.

II.K.3.3 Failure of PORV or Safety Valve to Close

Position

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report. This requirement is to be met before fuel load.

Response

HCGS will report any failure of a safety relief valve to close. A written report in the form of a Licensee Event Report will be submitted within 30 days as required by Section 50.73 of 10CFR Part 50.

The PSE&G HCGS annual report to the NRC will list each safety relief valve which is challenged during the year and will include the number of times each is challenged. This reporting requirement will be included in the HCGS Technical Specifications.

II.K.3.5 Automatic Trip of Reactor Coolant Pumps During LOCA

Response

This requirement is not applicable to HCGS.

II.K.3.7 Evaluation of PORV Opening Probability During Overpressure Transient

Response

This requirement is not applicable to HCGS.

II.K.3.9 Proportional Integral Derivative (PID) Controller Modification

Response

This requirement is not applicable to HCGS.

II.K.3.10 Proposed Anticipatory Trip Modification

Response

This requirement is not applicable to HCGS.

II.K.3.11 Justification in the Use of Certain PORVs

Response

There are no PORVs at HCGS. The ADS system employs five safety/relief valves to depressurize the reactor so that flow from LPCI and/or the core spray systems enters the reactor in the event that RCIC and/or the HPCI system cannot maintain the reactor water level. See Sections 5.2.2 and 7.3 for further discussion.

II.K.3.12 Confirm Existence of Anticipatory Reactor Trip Upon Turbine Trip

Response

This requirement is not applicable to HCGS.

II.K.3.13 Separation of HPCI and RCIC System Initiation Levels - Analysis and Implementation

Position

Currently, the Reactor Core Isolation Cooling (RCIC) System and the High Pressure Coolant Injection (HPCI) System both initiate on the same low water level signal and both isolate on the same high water level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the RCIC system initiation logic should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff and changes should be implemented if justified by the analysis.

Response

PSE&G concurs with the BWROG position on the separation of the HPCI and RCIC setpoints, which was transmitted to the NRC by letter from R.H. Bucholz (GE) to D.G. Eisenhut (NRC), October 1, 1980 (MFN-169-80).

This letter forwarded a GE study that showed that HPCI and RCIC initiations at the current low water level setpoints is within the design basis thermal fatigue analysis of the reactor vessel and its internals. Separating HPCI and RCIC setpoints as means of reducing thermal cycles has been shown to be of negligible benefit. In addition, raising the RCIC setpoint or lowering the HPCI setpoint has undesirable consequences that outweigh the benefit of the limited reduction in thermal cycles. Therefore, when evaluated on this basis, PSE&G concludes that no change in RCIC or HPCI setpoints is required.

PSE&G also concurs with the BWROG position that RCIC should restart automatically following a trip of the system at high reactor vessel water level. Instead of a RCIC turbine trip, which required operator action to allow restart of the system, the steam supply valve (E51-F045) to the turbine is closed to shut down the turbine and pump. Four separate transmitter/trip units energize individual relays, arranged in a one-out-of-two-twice logic configuration, to provide the closure signal for the valve. If the reactor water level subsequently decreases to level 2, the system initiation logic circuitry will reopen the steam supply valve, restarting the RCIC operation. This position was transmitted to the NRC by letter from D.B. Waters (BWROG) to D.G. Eisenhut (NRC), December 29, 1980. Therefore, the design of the RCIC system reflects this position. The RCIC system starts automatically when reactor water reaches a predetermined low level. The system is automatically shut off at a predetermined high level to prevent flooding of the steam lines. An automatic reset follows a high level trip. The RCIC system would then restart automatically on a subsequent low water level.

I.K.3.15 <u>Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems</u>

<u>Position</u>

The HPCI and RCIC systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe break detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation.

Submit sufficient documentation to support a reasonable assurance finding by the NRC that the modifications, as implemented, have resulted in satisfying the concerns expressed in the previous requirements.

Response

Each HPCI and RCIC steam supply line is provided with two normally open isolation valves. These valves close automatically upon receipt of an isolation signal. Each line contains a flow metering device. The HPCI and RCIC leak detection systems are Q-listed (Item XV.e.2 of Table 3.2-1).

The flow sensing system will initiate closure of the isolation valves when the flow in that line exceeds 300 percent of rated. The issue raised by the NRC in NUREG-0737 was that the 300 percent setpoint may be momentarily exceeded during the HPCI/RCIC start sequences. The HCGS design incorporates an addition of a time delay to the break detection circuitry, which directly addresses the problem and has no impact on the currently documented accident analyses of the HPCI/RCIC steam supply line breaks.

The design objectives have been met by replacing the previously installed isolation relay in each break detection circuit with a Class 1E time delay (approximately 3 seconds) relay to prevent inadvertent isolations during transient (startup) changes in steam flow.

II.K.3.16 Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modifications

Position

Failure of the power-operated relief valve to reclose during the TMI-2 accident resulted in damage to the reactor core. As a consequence, relief valves in all plants, including boiling water reactors, are being examined with a view toward their possible role in a small break loss-of-coolant accident.

The safety/relief valves are dual function pilot operated relief valves that use a spring actuated pilot for the safety function and an external air diaphragm actuated pilot for the relief function.

The operating history of the safety/relief valves has been poor. A new design is used in some plants, but the operational history is too brief to evaluate the effectiveness of the new design. Another way of improving the performance of the valves is to reduce the number of challenges to the valves. This may be done by the methods described above or by other means. The feasibility and contraindications of reducing the number of challenges to the valves by the various methods should be studied. Those changes which are shown to decrease the number of challenges without compromising the performance of the valves or other systems should be implemented.

Results of the evaluation shall be submitted by April 1, 1981 for staff review. Documentation of the staff approved modification will be provided by January 1, 1982. The actual modification will be accomplished during the next scheduled refueling outage after January 1, 1982 (if required).

Response

The NRC staff safety evaluation of the BWR Owners' Group response to NUREG-0737 Item II.K.3.16 states that the following modifications are acceptable methods of reducing SRV challenges and failures:

1. Providing a low-low set (LLS) relief logic system or developing procedures for Equivalent Manual Actions

2. Lowering the reactor pressure vessel water level isolation setpoint for main steam isolation valve (MSIV) closure from level 2 to level 1

3. Increasing the SRV simmer margin

4. Instituting a preventive maintenance program.

HCGS has provided a low-low set relief logic system based on the BWROG's generic design. The low-low set relief logic is Q-listed (Item XV.b.1 of Table 3.2-1). HCGS has implemented a MSIV closure setpoint change. The setpoint has been changed from an RPV Level 2 to Level 1 as indicated in Plant Drawing M-42-1. No changes will be made to the SRV simmer margin. The simmer margin is the difference between the SRV set pressure and the reactor pressure vessel operating pressure. The SRV set pressures are listed in Table 5.2-3. The RPV operating pressure is 1000 psig under steady state conditions. Therefore, the simmer margins, under steady state conditions, range from 108 to 130 psi. These values meet the intent of the 120 psi value recommended in General Electric Service Information Letter 196, Supplement 3.

Besides the design changes, HCGS is committed to implementing an SRV preventative maintenance program. The program will be based on information on operational feedback experiences found in such publications as NRC Inspection and Enforcement Bulletins, Information Notices, and General Electric service information letters. Maintenance procedures are available.

II.K.3.17 Report on Outages of ECCS Systems Licensee Report and Proposed Technical Specification Changes

Position

Several components of the Emergency Core Cooling (ECC) Systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel generator; 14 days for the high pressure coolant injection system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain 1) outage dates and duration of outages; 2) causes of the outage; 3) ECC systems or components involved in the outage; and 4) corrective action taken. Tests and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicants for an operating license shall establish a plan to meet these requirements.

<u>Response</u>

All unplanned ECCS outages are documented as a condition adverse to quality reported in the corrective action program. These reports are used to generate licensee event reports (LERs) in accordance with 10CFR50.73, as applicable.

Planned ECCS outages are documented in the OS/CRS daily log. Analysis of failure trends is accomplished by means of the LER system, corrective action program, MRule activities, etc., which requires a review of previous occurrences. Identified trends are further analyzed by Onsite Independent Review and/or the Nuclear Maintenance Programs personnel.

II.K.3.18 <u>Modification of ADS Logic - Feasibility for Increased Diversity for Some Event Sequences</u>

<u>Position</u>

The Automatic Depressurization System (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor-vessel water level provided no high pressure coolant injection or high pressure core spray flow exists and a low pressure Emergency Core Cooling (ECC) System is running. This logic would complement, not replace, the existing ADS actuation logic.

Response

GE performed a study for the BWR Owners Group and a revised report, NEDO - 24951, which identified eight optional means for resolution of this issue and was submitted to the NRC on October 28, 1982. The NRC judged acceptable either Option 2 (Eliminate High Drywell Pressure Trip and Add Manual Inhibit Switch) or Option 4 (Bypass High Drywell Pressure Trip and Add Manual Inhibit Switch). HCGS design incorporates Option 4.

This further automates the ADS by providing initiation, if required, for events that result in loss of coolant without an increase in the drywell pressure such as a pipe break outside the drywell or stuck open SRVs.

The manual inhibit switch allows the operator to inhibit ADS operation without having to repeatedly press the reset switch. The use of the inhibit switch is addressed in plant operating procedures OP-EO.ZZ-101(Q), "Reactor Pressure Vessel Control," and OP-EO.ZZ-201(Q), "Level Restoration."

These modifications have been incorporated in the HCGS design.

The ADS logic including the modifications due to this TMI item is Q-listed (Item XV.b.1 of Table 3.2-1).

II.K.3.21 Restart of Core Spray and LPCI Systems

Position

The core spray and LPCI system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart if required to assure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

Part a

By January 1, 1981, each licensee shall submit proposed design modifications and supporting analysis which will contain sufficient information to support a reasonable assurance finding by the NRC that the above position is met. The documentation should include as a minimum:

1. A discussion of the design with respect to the above paragraphs of Institute of Electronics and Electrical Engineers Standard 279-1971.

2. Support information including system design description, logic diagrams, electrical schematics, piping and instrument diagrams, test procedures and technical specifications.

3. Sufficient documentation to demonstrate that the system, as modified, would not degrade proper system functions.

Part b

Licensee to implement modifications at the next refueling outage following staff approval of the design unless this outage is scheduled within 6 months of the approval date. In this event, modifications will be completed during the following refueling outage.

Response

PSE&G concurs with the BWROG position, which is stated in NEDO-24951. The conclusion of the study is that the current BWR ECCS control logic as well as the core spray and LPCI logic is adequate, and no change is required.

II.K.3.22 Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design

Position

The Reactor Core Isolation Cooling (RCIC) System takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. The switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Response

The HCGS design incorporates an automatic transfer to the suppression pool when the condensate storage tank (CST) water reaches a predetermined low level. The RCIC suction transfer is Q-listed (Item XV.c.1 of Table 3.2-1). The subject valves are interlocked so that one must open before the other closes. For more details, see Sections 5.4.6.1 and 7.4.1.1.2.

II.K.3.24 Confirm Adequacy of Space Cooling for HPCI and RCIC Systems

Position

Long term operation of the reactor core isolation cooling and high pressure coolant injection systems may require space cooling to maintain the pump room temperatures within allowable limits. Applications should verify the acceptability of the consequences of a complete loss of alternating current power. The reactor core isolation cooling and high pressure core injection systems should be designed to withstand a complete loss of offsite alternating current power to their support systems, including coolers, for at least 2 hours.

Confirm that HPCI and RCIC room cooling can be maintained to enable continuous operation during a loss of offsite ac power for 2 hours.

Response

The HPCI and RCIC room unit coolers and their support systems are designed to withstand the consequences of a complete loss of offsite ac power since these are powered from onsite diesel generators. Each HPCI and RCIC room is provided with a 100 percent capacity redundant unit cooler. The HPCI and RCIC room unit coolers are Q-listed (Item XIII.c.2 of Table 3.2-1).

II.K.3.25 Effect of Loss of AC Power on Pump Seals

Position

The licensees should determine, on a plant specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current power for at least 2 hours. Adequacy of the seal design should be demonstrated. The results of the evaluation and proposed modifications are due by July 1, 1981. Modifications are to be implemented by January 1, 1982.

Clarification

The intent of this position is to prevent excessive loss of reactor coolant system inventory following an anticipated operational occurrence. Loss of alternating current power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump seal coolers for 2 hours, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump.

Response

At HCGS, cooling to the reactor recirculation pump seals is provided by the Reactor Auxiliaries Cooling System (RACS). RACS is automatically energized from the Class 1E standby diesel generators during LOP. The recirculation pump sealing cooling water supply system (RAC and CRD) are not Q-listed (Item XI.c and IV of Table 3.2-1).

PSE&G concurs with the BWROG study of this issue. BWROG submittals to the NRC on September 21, 1981, and September 2, 1982 provided test data showing very small seal leakage (on the order of 1 gpm) for a loss of seal cooling for longer than two hours. These results are applicable to the Byron-Jackson pumps used at HCGS. The normal or emergency controls for reactor water level could easily accommodate this small leakage rate.

II.K.3.27 Provide Common Reference Level for Vessel Level Instrumentation

Position

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points.

The applicant is to submit documentation by January 1, 1981 and implement action by April 1, 1981.

Response

The Hope Creek position on TMI issue II.K.3.27 was the current BWROG study, NEDO-24951, which stated that the current BWR water level indication system is fully adequate to allow plant operations to respond properly under all postulated reactor conditions and that there are no required design changes based on any plant safety considerations.

This evaluation was rejected by the NRC as explained in the letter from D.G. Eisenhut to D.B. Waters, dated April 6, 1981. In this letter, the NRC stated its position that "... all level instruments should be referenced to the same point. The selection of the reference point for any specific reactor has been left to the discretion of the licensee..." In light of this situation, HCGS has established the bottom of the dryer skirt as the common reference point for instruments measuring water level in the reactor vessel.

See Table 3.2 for listing of existing level instrumentation.

II.K.3.28 Verify Qualification of Accumulators on ADS Valves

Position

Safety analysis reports claim that air or nitrogen accumulators for the Automatic Depressurization System (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. General Electric has also stated that the Emergency Core Cooling (ECC) Systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee and applicant should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee and applicant must show that the accumulator design is still acceptable.

Clarification

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments and taking no credit for nonsafety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

Response

See Section 6.3 for a discussion of the ADS and see Section 9.3.6 for a discussion of the Containment Instrument Gas System. The ADS valves, accumulators and associated equipment and instrumentation are Q-listed (Item II.1, II.b, II.c XV.b.1 & 11 and XVII.b of Table 3.2-1).

II.K.3.30 Revised Small Break LOCA Methods to Shop Compliance with 10CFR50, Appendix K

Position

The analysis methods used by nuclear steam supply system vendors and/or fuel suppliers for small break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Clarification

As a result of the accident at TMI-2, the Bulletins and Orders Task Force was formed within the Office of Nuclear Reactor Regulation. This task force was charged, in part, to review the analytical predictions of feedwater transients and small break LOCAs for the purpose of assuring the continued safe operation of all operating reactors, including a determination of acceptability of emergency guidelines for operators.

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each light water reactor (LWR) vendor's models, were documented in the task force reports for each LWR vendor. In addition to the modeling concerns identified, the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small break LOCA model as required by II.4 of Appendix K to 10CFR Part 50 was needed. This included providing predictions of Semiscale Test S-07-10B, LOFT Test (L3-1), and providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small break LOCAs.

Based on the cumulative staff requirements for additional small break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor. These concerns should be reviewed in total by each holder of an approved emergency core cooling system model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small break test series and LOFT Test (L3-1) and (L3-2). The staff believes that the present small break LOCA models can be both qualitatively and quantitatively assessed against these tests.

Other separate effects tests (e.g., Oak Ridge National Laboratory core uncover tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify 1) which areas of the models, if any, the licensee intends to upgrade, 2) which areas the licensee intends to address by further justification of acceptability, 3) test data to be used as part of the overall verification/upgrade effort, and 4) the estimated schedule for performing the necessary work and submitted this information for staff review and approval.

Response

General Electric provided information concerning the NRC's small break model concerns in a meeting between GE and the NRC staff held on June 18, 1981 and subsequent documentation included in a letter from R.H. Bucholz (GE) to D.G. Eisenhut (NRC) dated June 26, 1981. Based on its review of this information, the NRC staff has prepared a safety evaluation report (SER) that concludes the test data comparisons and other information submitted by GE acceptably demonstrate that the existing GE small break model is in compliance with 10CFR50, Appendix K and, therefore, no model changes are required. The SAFER/GESTR-LOCA methodology, presented in reference 1, applies to the small breaks.

Response Reference

1. "General Electric Standard Application for Reactor Fuel (GESTAR II) (US Supplement)", NEDE-24011-P-A-US (latest approved revision).

II.K.3.31 Plant Specific Calculations to Show Compliance with 10CFR50.46

Position

Plant specific calculations using NRC approved models for small break loss of-coolant accidents as described in II.K.3 Item 30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees.

Calculations to be submitted by January 1, 1983 or 1 year after staff approval of loss-of-coolant accident analysis models, whichever is later (required only if model changes have been made).

Response

Small break LOCA calculations are described in Section 6.3.3.7, and the results are summarized in Table 6.3-4. The references in Section 6.3.6 describe the currently approved Appendix K methodology used. Compliance with 10CFR50.46 has been previously established by the NRC. No model changes are necessary (see response to Item II.K.3.30).

II.K.3.44 Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure

Position

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncover. Transients which result in a stuck open relief valve should be included in this category. The results of the evaluation are due January 1, 1981.

Response

The BWROG has prepared a generic response (NEDO-24951) to this requirement. The report was transmitted to D.G. Eisenhut by a letter from D.B. Waters on December 29, 1980. This response contains an evaluation of analyses performed to demonstrate that the core remains covered or no significant fuel damage occurs from an anticipated transient with a single failure. The report is applicable to HCGS and concludes that the core remains covered for all evaluated combinations of anticipated transients and single failures.

II.K.3.45 Evaluation of Depressurization with Other Than ADS

Position

Analyses to support depressurization modes other than full actuation of the automatic depressurization system (e.g., early blowdown with one or two safety/relief valves) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

Response

The BWROG submitted a generic response (NEDO-24951) to this requirement. This response was transmitted by letter to D.G. Eisenhut from D.B. Waters on December 29, 1980. This report concludes that a full ADS actuation is within the vessel integrity limits, that slower depressurization rates provide little benefit on vessel fatigue usage relative to full ADS, and slower depressurization rates can have an adverse impact on core cooling capability. The report is applicable to HCGS.

II.K.3.46 Responding to Michelson Concerns

Position

General Electric should provide a response to the Michelson concerns as they relate to boiling water reactors.

Clarification

General Electric provided a response to the Michelson concerns as they relate to boiling water reactors by letter dated February 21, 1980. Licensees and applicants should assess applicability and adequacy of this response to their plants.

Response

The February 21, 1980 letter to D.F. Ross of the NRC from R.H. Bucholz of G.E. addresses the Michelson concerns. This letter is applicable to HCGS.

III.A.1.1 Emergency Preparedness, Short Term

Position

Comply with Appendix E to 10CFR Part 50 and Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and meet the essential elements of NUREG-75/111, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," or have a favorable finding from the Federal Emergency Management Agency (FEMA).

Response

Emergency planning is discussed in Section 13.3. HCGS complies with NUREG-0654, Revision 1, dated January 1981, endorsed by Regulatory Guide 1.101, Revision 2, and 10CFR50, Appendix E.

Activities covered by the QA program are delineated in the QATR and include emergency plans.

III.A.1.2 Upgrade Emergency Support Facilities

Position

Establish an interim onsite Technical Support Center (TSC) separate from, but close to, the control room for engineering and management support of reactor operations during an accident. The Center shall be large enough for the necessary utility personnel and five NRC personnel, have direct display or callup of plant parameters, and dedicated communication with the control room, emergency operations facility, and the NRC. Provide a description of and a completion schedule for establishing a permanent TSC in accordance with the regulatory position of NUREG-0696, "Functional Criteria for Emergency Response" (February 1981).

Establish an onsite Operations Support Center; separate from but with communications to the control room for use by operation support personnel during an accident.

Designate a near site Emergency Operations Facility (EOF) with communications with the plant to provide evaluation of radiological releases and coordination of all onsite and offsite activities during an accident.

These requirements shall be met before fuel loading.

Response

HCGS is designed and operated in accordance with the intent of Item III.A.1.2, as amended by Supplement 1 to NUREG-0737.

The display system available to the TSC and EOF is described in Section 7.5. The technical support center (TSC) is a two floor structure located in the corner of the Reactor Building. The room arrangement has been finalized. Two Control Room Integrated Display Systems (CRIDS) CRTs and a meteorological and radiation monitoring system CRT will be installed in the facility.

The emergency operations facility (EOF) is located in the Training Center. The required data will be transmitted to the EOF via microwave with a computer telephone line backup.

The Emergency Response Facilities Data Acquisition System (ERFDAS) is listed in Item XV.d of Table 3.2-1.

III.A.2 Emergency Preparedness

Position

1. Each nuclear facility shall upgrade its emergency plan to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement are delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

2. Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations.

Response

The operation of HCGS will be in accordance with the criteria delineated in NUREG-0654. An emergency response exercise will be conducted for the HCGS prior to issuance of a full power license. Emergency planning is discussed in Section 13.3.

III.D.1.1 Primary Coolant Outside Containment

Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1. Immediate leak reduction

   (a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   (b) Measure actual leakage rates with system in operation and report them to the NRC.

2. Continuing Leak Reduction-Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Clarification

Applicants shall provide a summary description, together with initial leaktest results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident.

1. Systems that should be leak tested are as follows (any other plant system which has similar functions or post accident characteristics even through not specified herein, should be included):

   (a) Residual heat removal

(b) Containment spray recirculation

(c) High-pressure injection recirculation

(d) Containment and primary coolant sampling

(e) Reactor core isolation cooling

(f) Makeup and letdown (pressurized water reactors only)

(g) Waste gas (includes headers and cover gas system outside of containment in addition to decay or storage system).

Include a list of systems containing radioactive materials which are excluded from program and provide justification for exclusion.

2. Testing of gaseous systems should include helium leak detection or equivalent testing methods.

3. Should consider program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to all operating nuclear power plants regarding North Anna and Related incidents, dated October 17, 1979.

Response

1. The following are systems which penetrate containment and are likely to contain high radioactive fluids during or after a serious transient or accident and are included in the leakage reduction program.

(a) RCIC

(b) RHR

(c) Core Spray

(d) HPCI

(e) Hydrogen/Oxygen Analyzer System

(f) Post-Accident Sampling

(g) Containment Hydrogen Recombination

(h) Control Rod Drive Hydraulic System (SCRAM discharge portion)

2. The following design features and provisions are incorporated in these systems to minimize the leakage from the system boundary.

   (a) The pumps are provided with mechanical seals

   (b) The piping is welded construction.

   (c) The boundaries of the systems are isolated by one of the following means:

      1. One normally closed manual valve (low pressure piping)

      2. Two normally closed manual valves

      3. Two check valves

      4. One remotely actuated valve and a check valve

      5. Two remotely actuated valves

      6. One safety/relief valve or rupture disk

3. The leakage reduction program is an ongoing program that includes periodic tests and visual examinations to identify leakage from the system boundary.

4. Liquid Systems

   Systems containing liquids will be tested by recirculation of the test water back to the source, if possible. The system pressure will reflect that expected during an accident. Systems or portions of systems outside containment which normally operate at a pressure less than accident pressure will be examined for leakage during the Containment Integrated Leakage Rate Test described in Section 6.2.6.1. Typical areas that will be inspected for leakage are valve stems, pump seals, vents, drains, pump casing joints, valve bonnet joints, and flanges. All leakage will be evaluated and corrective action taken where necessary.

5. Steam Systems

   Systems containing steam will be tested using steam at operating conditions, if possible. Corrective action will be taken to reduce the leakage as necessary.

6. Gas Systems

   Systems containing highly radioactive gases post-accident, i.e., connected to the containment atmosphere, will be pressurized using a gas to the accident conditions. Leakage can be identified by using a tracer gas, monitoring pressure decay metering the gas makeup or using a bubble test. Corrective action will be taken to eliminate any observed leakage.

7. Containment Isolation Valves and Piping

   The containment isolation valves will be tested for leakage in accordance with 10CFR50 Appendix J, Option B, as discussed in Section 6.2.4. Therefore, these valves need not be included in the leak test program.

8. Test Frequency

The systems will be inspected for leakage during refueling outages at intervals not to exceed 24 months.

9. The following systems are excluded from the leakage reduction program for the reasons given below:

(a) Reactor Recirculation System - The system is contained completely within the containment.

(b) Reactor Water Cleanup - The RWCU is isolated at the containment boundary by the containment isolation valves.

(c) Main Steam System - The Main Steam System is isolated at the containment boundary by the main steam isolation valves.

(d) Feedwater System - The Feedwater System is isolated at the containment boundary by the feedwater isolation valves.

(e) Process Sampling System - The Process Sampling System is isolated at the containment boundary by the containment isolation valves. Post-accident samples will be obtained by the post-accident sampling system.

(f) Suppression Pool Cleanup System - The Suppression Pool Cleanup System is isolated at the containment boundary by the containment isolation valves.

(g) Plant Leak Detection System - The Containment Radiation Sampling System used to detect primary leakage is isolated at the containment boundary by the containment isolation valves.

(h) Containment Inerting and Purging System - The Containment Inerting and Purging System is isolated at the containment boundary by the containment isolation valves.

(i) Gaseous Radwaste System - The Gaseous Radwaste System (off-gas) receives its input from the Condensate Air Removal System. The main steam line isolation valves prevent highly radioactive steam from reaching the condenser and the Gaseous Radwaste System.

(j) Reactor Building Ventilation System - The RBVS supply and exhaust are isolated on a high radiation signal.

(k) Liquid Radwaste System - The drywell sump discharge is isolated at the containment boundary by the containment isolation valves.

(l) Radwaste Tank Vents - The radwaste tanks are vented to the radwaste tank filter units as described in Section 9.4.3. This vent system will not receive highly radioactive gases post-accident because the radwaste system is isolated at the containment boundary.

10. The concerns expressed in the October 1979 letter regarding the North Anna incident are resolved in the design for the radwaste tank vents described in Section 9.4.3. The drainage, ventilation and radwaste systems are described in Sections 9.3.3, 9.3.4 and Section 11. The discussion for each system describes the tests and inspections used to verify proper system operation.

III.D.3.3 Improved Inplant Iodine Instrumentation Under Accident Conditions

Position

1. Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

2. Each applicant for a fuel loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedure necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

Clarification

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

1. The physical size of the auxiliary and/or Fuel Handling Building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

2. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

3. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

4. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

For applicants with fuel loading dates prior to January 1, 1981, provide by fuel loading (until January 1, 1981) the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart mounted iodine sampler with attached single channel analyzer (SCA). The SCA window should be calibrated to the 365 keV of iodine-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

<u>Response</u>

A description of the equipment, training, and procedures has been provided in Section 12.5.3. Activities covered by the QA program are delineated in the QATR.

III.D.3.4 Control Room Habitability

Position

In accordance with Item III.D.3.4, "Control Room Habitability", applicants shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design basis accident conditions (GDC 19).

Clarification

1. All applicants must make a submittal to us regardless of whether or not they met the criteria of the referenced Standard Review Plan sections. The new clarification specifies that applicants that meet the criteria of the Standard Review Plans should provide the basis for their conclusion that Section 6.4 of the Standard Review Plan requirements are met. Applicants may establish this basis by referencing past submittals to us and/or providing new or additional information to supplement past submittals.

2. All applicants with control rooms that meet the criteria of the following sections of the Standard Review Plan:

2.2.1,2.2.2	Identification of Potential Hazards in Site Vicinity,
2.2.3	Evaluation of Potential Accidents, and
6.4	Habitability Systems

shall report their findings regarding the specific Standard Review Plan sections as explained below. The following documents should be used for guidance:

(a) Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release".

(b) Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release".

(c) K.G. Murphy and K.M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19", 13th AEC Air Cleaning Conference, August 1974.

Applicants shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, applicants may reference their past submittals. Applicants should, however, ensure that these submittals reflect the current facility design and that the information requested in Table III.D.3.4-1 is provided.

3. All applicants with control rooms that do not meet the criteria of the above listed references, Standard Review Plans, regulatory guides, and other references shall perform the necessary evaluations and identify appropriate modifications.

Each applicant submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from design basis accidents. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant boundary.

Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of the control room habitability but is not all inclusive.

The design basis accident radiation source term should be for the loss-of-coolant accident containment leakage and engineered safety features leakage contribution outside containment as described in Appendices A and B in Section 15.6.5 of the Standard Review Plan. In addition, boiling water reactor facility evaluations should add any leakage from the main steam isolation valves (i.e., valve steam leakage, valve seat leakage, main steam isolation valve leakage control system release) to the containment leakage and engineered safety features leakage following a loss-of-coolant accident. This should not be construed as altering our recommendations in Section D of Regulatory Guide 1.95 (Rev 2) regarding main steam isolation valve leakage control systems. Other design basis accidents should be reviewed to determine whether they might constitute a more severe control room hazard than the loss-of-coolant accident.

In addition to the accident analysis results, which should either identify the possible need for control room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control room operators to remain in the control room to take appropriate actions required by GDC 19, the applicant should submit sufficient information needed for an independent evaluation of the adequacy of the habitability systems. Table III.D.3.4-1 lists the information that should be provided along with applicant's evaluation.

TABLE III.D.3.4-1

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION

1. Control room mode operation, i.e., pressurization and filter recirculation for radiological accident isolation or chlorine release

2. Control room characteristics:

   (a) air volume control room

   (b) control room emergency zone (control room, critical files, kitchen, washroom, computer room, etc.)

   (c) control room ventilation system schematic with normal and emergency air flow rates

   (d) infiltration leakage rate

   (e) high efficiency particulate air filter and charcoal adsorber efficiencies

   (f) closest distance between containment and air intake

   (g) layout of control room, air intakes, Containment Building, and chlorine, or other chemical storage facility with dimensions

   (h) control room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc.

   (i) automatic isolation capability damper closing time, damper leakage and area

   (j) chlorine detectors or toxic gas (local or remote)

TABLE III.D.3.4-1 (Cont)

(k) self-contained breathing apparatus availability (number)

(l) bottled air supply (hours supply)

(m) emergency food and potable water supply (how many days and how many people)

(n) control-room personnel capacity (normal and emergency)

(o) potassium iodide drug supply

3. Onsite storage of chlorine and other hazardous chemicals:

   (a) total amount and size of container

   (b) closest distance from control room air intake

4. Offsite manufacturing, storage, or transportation facilities of hazardous chemicals

   (a) identify facilities within a 5-mile radius

   (b) distance from control room

   (c) quantity of hazardous chemicals in one container

   (d) frequency of hazardous chemical transportation traffic (truck, rail, and barge)

5. Technical Specifications (refer to standard Technical Specifications)

   (a) chlorine detection system

(b) control room emergency filtration system including the capability to maintain the control room pressurization at 1/8-inch water gauge, verification of isolation by test signals and damper closure times, and filter testing requirements.

Response

See Section 6.4 for a discussion of control room habitability.

1.11 DIFFERENCES FROM THE STANDARD REVIEW PLAN

The Code of Federal Regulations 50.34 (Title 10) requires an evaluation of the facility against NUREG-0800 the standard review plan (SRP), dated July 1981. The evaluation requires that the differences between the facility and the SRP be identified, described, and justified.

The results of the evaluation are detailed in a tabular format in Section 1.11.1. Also presented are justifications for those differences in the applicable sections of the FSAR which provide a basis for concluding that they are acceptable methods of complying with the regulations.

1.11.1 Differences From SRP Acceptance Criteria

The results of the evaluation are found in Table 1.11-1.

TABLE 1.11-1

SUMMARY OF DIFFERENCES FROM SRP

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
2.5.1 (Rev 2)	II Site information regarding unrelieved residual stresses in bedrock is required. (Section 2.5.1.2.4.C)	Unrelieved residual stresses have not been determined.	2.5.1.3
2.5.4 (Rev 1)	II For each set of conditions describing the occurrence of the maximum potential earthquake, the type of seismic waves producing the maximum ground motion and the significant frequencies must be determined. (Section 2.5.2.5)	Information required is not available for the plant site.	2.5.2.8
	II The amplitude and variation of acceleration at the ground surface, the effective frequency range, and the duration corresponding to each maximum potential earthquake must be identified. The spectral content for each pontential maximum earthquake should be described and based on consideration of the available ground motion time histories and regional characteristics of seismic wave transmission. (Section 2.5.2.6)	Earthquakes associated with geological structures and Tectonic Provinces were evaluated using the mean of the relationship between acceleration and Modified Mercalli Intensity units.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
3.2.1 (Rev 1)	II Regulatory Guide 1.29, Position C.1.b, requires that the reactor core and reactor vessel internals be designated Seismic Category I	Application of this guide is limited to those reactor vessel internals that are part of engineered safety features (ESFs), such as core spray piping, core spray sparger and hardware, etc.	3.2.1
	II Regulatory Guide 1.29, Position C.1.e, requires that portion of main steam extending from the outermost containment isolation valve to and including the turbine stop valve be designated Seismic Category I.	Portion of main steam line piping between main steam shutoff valve and the turbine main stop valve is not specifically designed to Seismic Category I standards and is not located in Seismic Category I structures.	1.8.1
	II Regulatory Guide 1.29, Position C.1.h, requires that cooling water and seal water systems required for functioning of reactor coolant pumps be classified as Seismic Category I.	Seal cooling piping for the reactor recirculation pump is not designed to withstand a safe shutdown earthquake (SSE).	
	II Regulatory Guide 1.29 Position C.2 requires that items whose continued function is not required but whose failure could reduce the functioning of the safety-related components to an unacceptable level should be designed to withstand an SSE.	Non-Seismic Category I items that may impact safety-related components are not specifically designed to withstand an SSE.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
3.2.2 (Rev 1)	II		1.8.1
	Regulatory Guide 1.26, Sections A&B, requires that Quality Group D components be safety-related.	Quality Group D components are not safety-related.	
	II		3.2.2.1
	Regulatory Guide 1.26 be used for establishing quality group standards for Quality Groups B, C, and D.	Some components were not specifically designed and fabricated to these quality group standards.	
3.5.3 (Rev 1)	Appendix A, Sect. II.1, Reinforced Concrete Members		3.8.4.8
	Permissible ductility ratios shall be in accordance with Regulatory Guide 1.142.	For flexural beams and slabs subjected to impactive loads, the permissible ductility ratios exceed those given in Regulatory Guide 1.142.	
	Appendix A, Sect.II.2, Structural Steel Members		3.8.4.8
	Permissible ductility ratios are listed.	For flexural beams subjected to impactive loads (other than tornado missiles) the permissible ductility ratio exceeds that given in Appendix A of SRP 3.5.3. For axial tension members subject to impulsive loads, a permissible ductility ratio of 3 is used.	
3.6.2 (Rev 1)	II.1		3.6.2.7
	Postulated pipe rupture locations in containment should meet MEB 3-1.	a) HCGS design for NSSS piping meets the provisions of Rev 0 (November 1973) of this SRP section, and not the current SRP (Rev 1, July 1981).	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
		b) Intermediate breaks on Class 1, 2, and 3 piping are not postulated unless such locations exceed stress and usage factor threshold levels per MEB 3-1 or are located in the proximity of welded pipe attachments.	
	II.3 This section refers to III.2.a(2), which states that the initial condition prior to postulated pipe rupture should be the greater of the contained energy at hot standby or at 102% power.	A pipe break initial condition of 100% power at normal plant conditions is used.	
3.7.1 (Rev 1)	II.1.b Design time history for seismic ground motion. Spectral values calculated from design time history should have frequency ranges in agreement with Table 3.7.1-1 or selection of a set of frequencies such that each frequency is within 10% of the previous one.	In the chosen set of frequencies for the 28 to 33 Hz range, each frequency is generally not within 10% of the previous one.	3.7.1.5
	II.1.b No more than five points of the spectra obtained from the design time history should fall below the design response spectra.	The spectra obtained from the design time history have more than eight points fall below the design response spectra for 1, 2, 5, and 7% damping.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
3.7.3 (Rev 1)	II.2.b		3.7.3.16
	Five operating basis earthquakes (OBEs), with a minimum of 10 cycles each, should be assumed during the plant life.	For NSSS components and equipment, 10 equivalent peak OBE cycles are used.	
3.8.2 (Rev 1)	II.4.f		3.8.2.8
	Design report is considered acceptable when it satisfies the guidelines of Appendix C to SRP 3.8.4.	Sufficient information is available in forms other than those outlined in Appendix C.	
	II.5		
	Table 3.8.2 lists allowable stress limits for steel containments.	Allowable stresses used for testing and post-flooding conditions are higher than indicated in SRP Table 3.8.2.	
3.8.3 (Rev 1)	II.2		3.8.4.8
	Interior structures of containments shall be designed in accordance with Specification ACI 349 as augmented by Regulatory Guide 1.142.	Interior structures are designed in accordance with Specification ACI 318-71.	
	II.4.e		3.8.2.8
	Design report described in Appendix C to SRP 3.8.4 is reviewed.	Sufficient information is available in forms other than those outlined in Appendix C.	
3.8.4 (Rev 1)	II.2		3.8.4.8
	Category I structures shall be designed in accordance with Specification ACI 349 as augmented by Regulatory Guide 1.142.	Category I structures are designed in accordance with Specification ACI 318-71.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.2		1.8.1
	Conformance to Regulatory Guides 1.10, 1.55 and 1.94.	Nonconformance, in part, with Regulatory Guides 1.10, 1.55, and 1.94.	
	II.4.d		3.8.2.8
	Design reports are acceptable if it contains the information specified in Appendix C.	Sufficient information is available in forms other than those outlined in Appendix C.	
	II.4.f		3.8.4.8.1
	Spent fuel rack material should conform to Section III, Subsection NF, of the ASME Code.	ASTM steel procured under an ANSI N45.2 Q.A. Program, instead of steel procured under an ASME Code Q.A. Program in accordance with Subsection NF, is used.	
3.8.5 (Rev 1)	II.4.e		3.8.2.8
	Design report is considered acceptable if it satisfies the guidelines of Appendix C to SRP 3.8.4.	Sufficient information is available in forms other than those outlined in Appendix C.	
3.9.3 (Rev 1)	II.1		3.9.3.5
	Acceptability of the combination of design and service loadings applicable to the design of Class 1, 2, and 3 components should be judged by comparison with positions stated in Appendix A of SRP 3.9.3.	Design and service loadings applicable to the design of Class 1, 2, and 3 components do not conform, in part, to Appendix A or SRP 3.9.3.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
3.9.5 (Rev 2)	II.b		3.9.5.4
	Design and construction of the core support structures is to conform to the requirement of Subsection NG of Section III of the ASME Code.	Design and construction of the core support structures do not specifically conform to Subsection NG of Section III of the ASME Code.	
	II.c		
	Design basis for reactor internals to conform to ASME III, Subsection NG 3000.	Reactor internals do not specifically conform to ASME III, Subsection NG 3000.	
3.11 (Rev 2)	II		3.11.5
	Environmental capability of equipment is to be demonstrated by appropriate testing and analysis.	Environmental qualification is performed by either one of the two methods: analysis or testing.	
	II		
	Complete and auditable records be available at time of OL application.	These records will be available in time for environmental qualification audit, prior to fuel load.	
	II		
	Auditable records be available to document the qualification of mechanical equipment.	The HCGS qualification program does not address Mechanical equipment.	
	II		
	IEEE-323 (augmented by Reg. Guide 1.89) as acceptance criteria is to be used for qualification program.	The HCGS equipment qualification program will comply with Reg. Guide 1.89 for equipment upgraded to NUREG 0588, Category I requirements.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
4.4 (Rev 1)	II.B		4.4.7
	Crud effects should be accounted for in the thermal-hydraulic design. Process monitoring should be capable of detecting a 3% pressure drop in the reactor coolant flow.	Crud effects and process monitoring to detect a 3% drop in reactor coolant flow are not explicitly addressed in FSAR.	
4.5.1 (Rev 2)	II.1		4.5.1.5
	Properties of materials for control drive mechanism are to be equivalent to those given in Appendix I to Section III of the ASME code.	Only components forming primary pressure boundary use code materials.	
4.5.2 (Rev 2)	II.2		4.5.2.6.1
	Welds fabricated per ASME Section III, NG-4000 must meet examination and acceptance criteria shown in NG-5000.	Welds are not performed in accordance with ASME III, NG-4000 and NG-5000 requirements.	
	II.3		4.5.2.6.2
	Nondestructive examination of wrought seamless tubular products and fittings shall be in accordance with ASME Code Section III, NG-2500 and NG-5300.	Tubular products are not supplied to ASME Code Section III, NG-2500 and NG-5300 requirements.	
	II.4		4.5.2.6.3
	Fabrication is to be in full compliance with Regulatory Guides 1.31 and 1.44.	Fabrication is not in full compliance with Regulatory Guides 1.31 and 1.44.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
5.2.1.1 (Rev 2)	II.1,2 Minimum quality standard for safety-related structures, systems, and components as established by 10 CFR 50.55a requires conformance with appropriate editions of specified published industry codes and standards.	Certain safety-related structures, systems, and components are purchased under different editions and addenda of the code.	5.2.1.3.1, 5.2.1.3.2 and 1.8.1
5.2.1.2 (Rev 2)	II.1,2 ASME Section III code case acceptability for safety related structures, systems and components is based on conformance to Regulatory Guides 1.84, 1.85, and 1.147.	Some code cases that have been used are not addressed in in applicable Regulatory Guides.	5.2.1.3.1, 5.2.1.3.2 and 1.8.1
5.2.3 (Rev 2)	II.3.b.(3) and II.4.d Regulatory Guide 1.71 states that performance qualifications should require testing of welders under simulated access conditions when physical conditions restrict welder's access. Requalification of welder is required when significantly different restricted accessibility conditions occur.	Welders are not tested under simulated access conditions and are not requalified for significantly different restricted accessibility conditions.	5.2.3.5.2 and 1.8.1
	II.4.d Regulatory Guide 1.31, Position e.1, requires that delta ferrite content verification tests on austenitic steel weld filler material be made using magnetic measuring devices.	Ferrite content is determined by chemical analysis.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.1.1		5.2.3.5.1
	Material specifications for reactor coolant pressure boundary (RCPB) materials are those identified in Appendix I of Section III or described in detail in Parts A, B, and C of Section II.	Requirements of Part B, Section II are not met. Design stress limits of ASME Section III, Appendix I are not used.	
	II.4.b.2		5.2.3.5.1
	Water quality for final cleaning or flushing of finished surfaces during installation per Regulatory Guide 1.37	Relevant sections of Regulatory Guide 1.37 are not imposed.	
5.2.4 (Rev 1)	II.7		5.2.4.8
	Exemptions from code examinations are in accordance with the criteria in IWB-1220.	Exemptions are not listed.	
5.2.5 (Rev 1)	II.1		5.2.5.11 and 1.8.1
	Application of Regulatory Guide 1.29 positions C-1 and and C-2 to Leak Detection System (LDS).	Portions of LDS are not qualified for a seismic event.	
5.3.1 (Rev 1)	II.2		5.3.1.8.1
	Reactor pressure vessel (RPV) and appurtenances are to be fabricated and installed to ASME Code Section III, Paragraph NB-4100.	Components are fabricated and installed to earlier edition of ASME, Section III, Code.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.3		5.3.1.8.2
	Nondestructive examination of RPV material to ASME Code, Section III NB-5000 (normal) or Appendix IX-6000 (special method).	Components are fabricated and installed to earlier edition of ASME, Section III, Code.	
	II.4.a		5.3.1.8.3
	Welding records of RPV ferritic and austenitic stainless steel are required by NB-4300 of Section III.	Welding records per NB-4300 of Section III are not specifically addressed.	
	II.4.e		5.3.1.8.4
	Regulatory Guides 1.37 and 1.44 in avoiding sensitization and contamination of RPV stainless steel.	Nonconformance to Regulatory Guide 1.37 as related to the RPV.	
	II.5 & II.6		5.3.1.8.5
	Appendices G and H of 10 CFR 50 regarding material testing and acceptance standards for fracture toughness.	Design and procurement of Hope Creek reactor vessel is not in total compliance with Appendices G and H.	
5.3.3 (Rev 1)	II.1		5.3.3.8
	Conformance to ASME B&PV code.	Reactor vessel does not have an ASME code "N" stamp.	
	II.2		
	Acceptable materials for reactor vessel parts are SA 533 Gr B Cl1, SA 508 Cl2 and SA 508 Cl3.	Additional materials for reactor vessel parts are used.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.4		
	Preservice inspection and flaw evaluation of RPV as required by ASME Code, Section XI.	ASME Section XI, preservice inspection and flaw criteria is not applied.	
5.4.8 (Rev 2)	II.1.a		5.4.8.4
	Reactor water demineralization is to operate at 1% of main steam flow rate.	Demineralization is accomplished with less than 1% of main steam flow rate.	
5.4.12 (Rev 0)	II.9		5.4.12.5
	Provisions to test for operability of the reactor coolant vent system should be part of the design.	Provisions for testing are not provided.	
6.1.1 (Rev 2)	II.A.1.a.2		6.1.1.3
	Regulatory Guide 1.44 requires corrosion testing for verification of nonsensitization of austenitic stainless steel components.	Corrosion tests are generally not performed.	
	II.A.1.a.4		
	Regulatory Guide 1.31, requires delta ferrite content verification of austenitic stainless steel weld filler material by tests using magnetic measuring devices.	Ferrite content is determined by chemical analysis.	
	II.A.1.b.1		
	ASME Code and Regulatory Guide 1.50 set requirements for the control of preheat for welding of low-alloy steel.	Weld procedures and practices are in full compliance with the code, but not strictly with all aspects of Regulatory Guide 1.50.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.B.1		
	Regulatory Guide 1.7, Position C.1, requires that capability be provided to mix containment atmosphere to control hydrogen generation following a LOCA.	Drywell fans are not safety-related. Analysis show that adequate mixing is obtained from convection, diffusion, and turbulence.	
6.1.2 (Rev 2)	II		6.1.2.1
	Compliance with Regulatory Guide 1.54 and the standards of ANSI N101.2 for NSSS coating systems inside the containment.	Noncompliance with Regulatory Guide 1.54 as related to ANSI 101.4.	
6.2.1.2 (Rev 2)	Criteria II.B.1		6.2.1.8
	Initial conditions for subcompartment analyses should be: RH=0, T=Maximum, P=Minimum (Page 6.2.1.2.2).	The subcompartment analyses for RPV shield annulus and drywell head were based on the following initial conditions: RH=30, T=135°F, and P=15.45 psia.	
6.2.3 (Rev 2)	II.3.e		6.2.3.6
	The external design pressure of the secondary containment structure should provide an adequate margin above the maximum expected external pressure.	The secondary containment for tornado depressurization is not designed with any margin above the maximum expected external pressure as stated in Regulatory Guide 1.76.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
6.2.4 (Rev 2)	II.6.d Valve nearest the containment and piping between the containment and the first valve, when both valves are located outside primary containment, should be enclosed in a leak-tight or controlled leakage housing.	An enclosure or leak-tight housing has not been designed.	6.2.4.5
	II.6.h All nonessential systems penetrating primary containment must be automatically isolated by the containment isolation signal.	There are valves in nonessential portions of systems where automatic isolation is not provided.	1.10.II.E.4.2/ 6.2.4.5
6.2.5 (Rev 2)	II.4 Following a LOCA, repressurization of the containment should be limited to less than 50% of containment design pressure.	Pressure increase due to main steam isolation valve (MSIV) inleakage after a LOCA will result in repressurization of more than 50% of the containment design pressure.	6.2.5.7
6.5.1 (Rev 2)	II Design of instrumentation for ESF atmosphere cleanup systems to the guidelines of Regulatory Guide 1.52 and to the recommendations of ANSI N509 as summarized in SRP Table 6.5.1-1.	Compliance with the minimum instrumentation requirements for the CREF system are discussed in Table 6.5-4 and for the FRVS systems in Table 6.8-5	6.5.1.2

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
6.5.1 (Rev 2)	II		6.5.1.1
	Relevant requirements of General Design Criteria 19, 41, 42, 61, and 64 as they relate to the Design Testing and Maintenance of ESF atmosphere cleanup system air filtration and absorption units are met by using the regulatory positions contained in Regulatory Guide 1.52.	Compliance with the recommendations of Regulatory Guide 1.52 are discussed in Section 1.8.1.52.	
7.1 (Rev 2)	Table 7-1		7.1.2.4(q)
	Conformance to Regulatory Guide 1.118.	Exception to Regulatory Guide 1.118.	
8.1 (Rev 2) Applies also to: 8.3.1 (Rev 2) and 8.3.2 (Rev 2)	Table 8-1		8.1.6 and 8.3.4
	Criteria Item F Regulatory Guide 1.75, IEEE-384-1981, requires that vertical separation between redundant Class 1E cable trays in the cable spreading room is to be at least 3 feet.	HCGS separation criteria allow 18 inches vertical separation for redundant Class 1E cable trays in the cable spreading room.	
	Table 8.1		
	Regulatory Guide 1.75, Position C.15, requires that safety class structures housing redundant Class 1E batteries should have independent ventilation systems.	HCGS design does not have complete independence for each battery room.	
9.1.2 (Rev 2)	II.1		9.1.2.5
	ANS 57.2, Paragraphs 5.1.1 and 6.4.1.(1) requires that the spent fuel pool to be designed to Seismic Category I.	Spent fuel liner plates are non-seismic Category I.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.6		
	ANS 57.2, Paragraph 5.4.1 requires that at least one radiation monitor with audible alarm shall be installed on the fuel handling machine.	No permanent radiation monitors are provided on the refueling machine.	
	II.6		
	ANS 57.2, Paragraph 5.4.2 requires that high and low level alarms shall be provided in the spent fuel building and in the control room to indicate if the pool water level falls below or exceeds predetermined limits.	High and low level alarms are provided only in the main control room.	
9.1.3 (Rev 1)	II.1.d.(4)		9.1.3.6
	The maximum normal spent fuel pool water temperature is 140°F with single failure of one heat exchanger.	The maximum normal spent fuel pool water temperature will exceed 140°F after the first refueling cycle of the plant.	
9.1.4 (Rev 2)	II.3 and 4		9.1.4.6
	Regulatory Guide 1.13, Position C.3, requires that interlocks be provided to prevent cranes from passing over stored fuel when fuel handling is not in progress.	The reactor building polar crane 10-ton auxiliary hoist is not physically restricted from traveling over the spent fuel pool.	
	II.3		
	ANS 57.1, Paragraph 6.2.1.1(a), requires that the auxiliary fuel handling crane be provided with an underload interlock.	The polar crane auxiliary hoist, which functions as the auxiliary fuel handling crane, is not provided with an underload interlock.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.5		
	The maximum potential kinetic energy capable of being developed by any load handled above stored spent fuel, if dropped, should not exceed the kinetic energy of one fuel assembly and its associated handling tool when dropped from the height of which it is normally handled above the spent fuel pool storage racks.	Light loads handled by the fuel pool jib cranes and the auxiliary hoist of the reactor building polar crane could exceed the maximum potential energy.	
9.1.5 (Rev 0)	II.2		9.1.5.6
	Regulatory Guide 1.13 Position C.3 Interlocks should be provided to prevent cranes from passing over stored fuel when fuel handling is not in progress.	The auxiliary hoist of the polar crane has no travel restriction.	
	II.2		
	NUREG 0612, para. 5.1.1(1) Load paths should be clearly marked on the floor in the areas where heavy loads are to be handled	Load paths are not painted on the floor.	
	II.2		
	ANS 57.1, para 6.2.1.1(a) Auxiliary fuel handling crane to be provided with an underload interlock that is actuated upon reduction in load while lowering.	The auxiliary hoist of the polar crane, which functions as the auxiliary fuel handling crane, has no underload interlock.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
9.3.2 (Rev 2)	II.5.a The post-accident sampling system should have the capability for measuring dissolved oxygen to required concentrations in the reactor coolant.	The PASS does provide a method for measuring dissolved oxygen as discussed in Section 9.3.2.6.	9.3.2.6
9.4.1 (Rev 2)	II Regulatory Guide 1.52, Position C.2a, states that engineered safety feature (ESF) atmosphere cleanup systems should include demisters prior to prefilters.	Demisters are used only where moisture impingement is a potential problem.	9.4.1.6
	II Regulatory Guide 1.52, Position C.2.j, states that ESF atmosphere cleanup units be designed and installed in a manner that permits replacement of one train as an intact unit or as a minimum number of sections.	The ESF atmosphere cleanup systems are not designed to be replaced as intact units or in segmented sections.	
9.4.2 (Rev 2)	II.3 Regulatory Guide 1.52, Position C.2.a, states that ESF atmosphere cleanup systems should include demisters prior to prefilters and HEPA filters ahead of the adsorbers.	Demisters are used only where moisture impingement is a potential problem. HEPA filters are not provided ahead of adsorbers when HEPA filters are normally present upstream of the ESF atmospheric cleanup units.	9.4.2.6

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.3		
	Regulatory Guide 1.52, Position C.2.j, states that ESF atmosphere cleanup units be designed and installed in a manner that permits replacement of one train as an intact unit or as a minimum number of sections.	The ESF atmosphere cleanup systems are not designed to be replaced as intact units or in segmented sections.	
	II.3		
	Regulatory Guide 1.140, Position C.2.a, requires that the flow rate of a single atmosphere cleanup train be limited to approximately 30.000 cfm.	The flow limit of 30,000 cfm per filter is exceeded in some of the exhaust systems of the normal ventilation systems.	
9.4.3 (Rev 2)	II		9.4.3.6
	Regulatory Guide 1.140, Position C.2.a, states that atmosphere cleanup systems in normal ventilation exhaust systems should consist of the following sequential components: HEPA filters before adsorbers, adsorbers, fans, and interspersed ducts, dampers, and related instrumentation.	The atmosphere cleanup units in the normal ventilation exhaust systems do not include all the sequential components required by Regulatory Guide 1.140.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
9.4.4 (Rev 2)	II.3		9.4.4.6
	Regulatory Guide 1.140, Position C.2.a, states that atmopshere cleanup systems in normal ventilation exahust systems should consist of the following sequential components: HEPA filters before adsorbers, adsorbers, fans, and interspersed ducts, dampers, and related instrumentation.	The atmosphere cleanup units in the normal ventilation exhaust systems do not include all the sequential components required by Regulatory Guide 1.140.	
9.4.5 (Rev 2)	II.5		9.4.5.6
	Regulatory Guide 1.52, Position C.2.a, states that ESF atmopshere cleanup systems should include demisters prior to prefilters and HEPA filters ahead of the adsorbers.	Demisters are used only where moisture impingement is a potential problem. HEPA filters are not provided ahead of adsorbers when HEPA filters are normally present upstream of the ESF atmospheric cleanup units.	
	II.5		
	Regulatory Guide 1.52, Position C.2.j, states that ESF atmopshere cleanup units be designed and installed in a manner that permits replacement of one train as an intact unit or as a minimum number of sections.	The ESF atmosphere cleanup systems are not designed to to be replaced as intact units or in segmented sections.	
	II		
	Regulatory Guide 1.140, Position C.2.b, requires that flow rate of single atmosphere cleanup train be limited to approximately 30,000 cfm.	The flow limit of 30,000 cfm per filter is exceeded in some of the exhaust systems of the normal ventilation systems.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
9.5.1 (Rev 3)	II.2		9.5.1.6
	All criteria paragraphs listed hereunder relate to BTP CMEB 9.5-1, Rev 2, 7/81.		
	C.1.c(2) requires that single active failure or crack in fire protection piping should not impair both the primary and backup fire suppression capability	HCGS complies with this requirement except for the auxiliary building - radwaste/service area, elevator shafts, and machine rooms for elevators 11-02 and 51-01 in the turbine and auxiliary buildings, circulating water pump structure, and the 1,000,000-gallon fuel oil storage tank in the yard area.	
	C.4 requires that the quality assurance program of the Contractors should ensure the guidelines for design, procurement, installation, and testing of the fire protection systems for safety related areas are satisfied.	HCGS complies with this requirement for the fuel oil tank, the fire pumps and associated controls, the fire protection water spray systems, the carbon dioxide systems, and the early warning smoke and detection systems in safety related areas. However the quality assurance program ('F' program) was formally implemented effective July 1, 1978. In view of that certain fire system components purchased and installed prior to July 1, 1978, such as the fire water storage tanks, the tank heaters and associated controls, and the valve pit heaters are excluded from the 'F' program during the construction phase. However, these components will be under the F program after fuel is delivered to the site.	
	C.5.a(1) requires separation of redundant divisions or trains of safety-related systems	See FSAR Appendix 9A for description of differences from this requirement.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.5.a.(3) requires openings for piping, conduit and cable trays in fire barriers be sealed	Some openings in fire barriers are not sealed, i.e., inside non-segregated phase bus ducts and openings in turbine operating deck for turbine CIVs. Also see FSAR Appendix 9A for additional differences from this requirement.	
	C.5.a.(4) requires that penetration openings for ventilation systems in fire barriers be provided with fire dampers.	Some penetration openings for ventilation systems are not provided with fire dampers. Also see FSAR Appendix 9A for additional differences from this requirement.	
	C.5.a(5) requires door openings in fire barriers be protected with equivalently rated doors, frame and hardware	HCGS complies with this requirement and provides Underwriters' Laboratories (UL) or Factory Mutual (FM) labeled doors for all openings except for those openings that exceed the maximum available UL or FM label doors size. UL Certificate of Inspection is provided for oversize fire doors.	
	C.5.a(8) allows only one redundant safety division per cable spreading room.	Both safety divisions are in one cable spreading room.	
	C.5.a(13) requires outdoor oil-filled transformers to be located at least 50 feet from building walls, or if within 50 feet, adjacent building walls shall have no openings and have a fire rating of at least 3 hours.	The transformers are less than 50 feet from building walls. All walls facing transformers have fire resistance rating of 2 hours and are not entirely free of openings.	
	C.5.b. requires one safe shutdown train be free of fire damage by separation of redundant shutdown trains by 3-hour fire barrier or other alternates.	See FSAR Appendix 9A for description of differences from this requirement.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.5.c. requires one safe shutdown train be free of fire damage	See FSAR Appendix 9A for description of difference from this requirement.	
	C.5.e(2) requires redundant safety-related cable system outside the cable spreading room to be separated from each other and from potential fire exposure hazards by 3-hour fire barrier or provided automatic water systems.	See FSAR Appendix 9A for description of differences from this requirement.	
	C.5.e(2) requires that redundant safety-related cable trays outside the spreading rooms to be provided with continuous line-type heat detectors.	Continuous line-type heat detectors are not provided. Instead, photoelectric and ionization detectors are installed in areas where safety-related cable trays are located.	
	C.5.e(2) also requires that safety-related cable trays shall be protected from potential exposure to fire by an automatic water suppression system where a fire could occur.	Not all safety-related cable trays are provided with a water suppression system.	
	Paragraph C.5.f(1) requires smoke and corrosive gases to be discharged directly outside and separate smoke and heat vents be provided for certain areas.	HCGS generally uses normal ventilation system to remove smoke and gases. A separate smoke system is provided for control area.	
	C.5.g.(3) states that a fixed emergency communication system independent of the normal plant communication system be installed at pre-selected stations.	HCGS has no specific emergency communication system intended solely for emergency situations.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.6.a(2) requires that fire detection systems comply with NFPA 72D, Class A systems.	Areas required for initial hot shutdown outside the reactor building and most areas of the reactor building, except the new fuel storage area, spent fuel pool, and above the cask loading pit, are provided with a Class A fire detection system. All other Class B fire detection systems. In addition, the operation and supervision of the fire protection system is not the sole function of the plant operator.	
	C.6.a(3) requires that the fire detectors be installed in accordance with NFPA 72E	Location of early warning fire and smoke detectors was determined by the detection system vendor, under the direction of a qualified fire protection engineer.	
	C.6.a(6) requires that secondary power supplies for electrically operated control valves be provided per NFPA 72D.	Secondary power is provided for motor operated valve, which is disconnected during a LOCA. Also the fire detection system is supplied with uninterruptible 120 V ac power.	
	C.6.b(6) requires that fire pump installation conform to NFPA 20	Fire pump installation conforms to NFPA 20 except the diesel fire pump fuel oil day tank is located outside and is subject to freezing, and the waste water line from the diesel fire pump heat exchanger is not provided with a open waste cone. Also, the pump test flow meter and test manifold are installed in series in the same test line.	
	C.6.b.(7) requires that hydrants be installed approximately every 250 feet on the yard main system	Hydrants are provided on the yard main, but in some areas the distance between hydrants is greater than 250 feet.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.6.b.(9) requires that failure in one fire water storage tank or its piping should not cause both tanks to drain	A leak in the fire pump suction pipe and either fire water storage tank could cause loss of water from both tanks.	
	C.6.b.(11) requires that the fire water supply should be calculated on basis of the largest expected flow from sprinkler system plus 500 gpm for hose streams	Table 9.5-18 lists the minimum and actual hose stream flows available for all hydraulically designed sprinkler systems.	
	C.6.c.(2) requires that all valves in the fire protection water system be periodically checked to verify position in accordance with NFPA 26.	Administratively controlled, locked valves are inspected monthly and electrically supervised valves are not periodically checked because they are constantly monitored.	
	C.6.c.(3) requires that fixed water extinguishing systems comply with the apppropriate NFPA Standard	NFPA deviations have been identified and evaluated. Significant deviations are identified in FSAR.	
	C.6.c.(4) requires that interior fire water hose installations be able to reach any location that contains or could present a fire exposure hazard to safety-related equipment with at least one effective hose stream using a maximum of 100 feet of hose.	At HCGS, certain hose stations are provided with an additional 50 feet of hose that is not connected and is stored near the fire hose station, which will be used to reach certain areas where 100 foot hoses will not reach.	
	C.6.c.(4) requires individual standpipes should be at least 4-inches in diameter for multiple hose connections.	HCGS provides 4-inch in diameter standpipes feeding multiple hose connection, but branches off standpipes feeding two or one hose connections are 3-inch in diameter.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.6.C.(4) states that provisions should be made to supply water to at least standpipes and hose connections for manual firefighting in areas containing equipment required for safe plant shutdown in the event of an SSE. Piping serving such hose stations should be analyzed for SSE loadings.	Firewater piping to hose stations and standpipes are not analyzed for SSE loadings and no cross-connection to a normal Seismic Category I water system is provided.	
	C.7.a.(1).(C) requires that the primary containment should be provided with fire detection systems including backup, general area, fire detection capability.	No fire protection systems are provided in the containment drywell.	
	C.7.b requires that ventilation openings between control room and peripheral rooms shall be provided with automatic smoke dampers.	HCGS has fire dampers in the return air ducts of the peripheral rooms.	
	C.7.b also requires peripheral rooms in the control room complex to be provided with automatic water suppression.	No automatic water suppression is provided in peripheral rooms of the main control room complex.	
	C.7.b also requires that smoke detectors be provided in the control room cabinets and consoles.	Smoke detectors are only provided in control room cabinets and consoles that include redundant safe shutdown equipment.	
	C.7.c requires primary fire suppression in cable spreading room be an automatic water system.	HCGS provides an automatic carbon dioxide in the control equipment mezzanine room (cable spreading room) at floor elevation 177 feet -6 inches of control area. A manual water deluge system is provided as a backup.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.7.c(2) requires aisle separation between tray stacks in cable spreading room be at least 3 feet wide and 8 feet high.	Main access aisles are less than 3 feet wide and 8 feet high in some areas of cable spreading rooms. A manual water deluge system is provided as backup.	
	C.7.c(5) requires continuous line-type heat detectors for cable trays inside the cable spreading room.	Continuous line-type heat detectors are not provided. Instead, photoelectric and ionization detectors are installed in areas where safety-related cable trays are located.	
	C.7.f requires redundant safety-related panels remote from the control room complex be separated from each other by a 3-hour fire barrier.	See Appendix 9A for description of differences from this requirement.	
	C.7.i requires automatic fire suppression system for the diesel generator areas be designed for operation when the diesel is running without affecting the diesel.	Inadvertent operation of one of the automatic carbon dioxide sytems provided for the diesel generator rooms could affect operation but not affect safe shutdown of the plant.	
	C.7.j requires diesel fuel oil tanks with capacity greater than 1,100 gallons not be located inside buildings containing safety-related equipment.	Two 26,500 gallon diesel fuel oil tanks are located in each of the four tank rooms in the auxiliary building - diesel area. Each room is surrounded by a 3-hour fire barrier and fire suppression and fire detection is provided for each room.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	C.7.k. requires redundant safety-related pumps be separated from each other parts of the plant by a 3-hour fire barrier.	3-hour fire barriers are provided to separate redundant safety-related trains to the extent noted in FSAR Appendix 9A. 3-hour fire barriers are not provided to separate safety-related pumps from other parts of the plant unless the fire hazard analysis indicated it is required to meet Appendix R to 10CFR50.	
	C.7.n requires that fire barriers, automatic fire suppression and detection be provided for the radwaste and decontamination areas.	In general fire barriers, automatic fire suppression and detection is provided for the radwaste and decontamination areas as indicated by the fire hazard analysis.	
9.5.8 (Rev 2)	II.1		9.5.8.6
	Regulatory Guide 1.117, Appendix Position 13, requires that emergency power systems, including all related auxiliary systems, be protected from the effects of tornado missiles.	Projections of the emergency diesel engine exhaust stacks above the roof are not provided with tornado missile barriers.	
11.3 (Rev 2)	II.B.6		11.3.5
	All gas analyzers shall be nonsparking (Page 11.3-6).	Gas analyzers have not specifically been purchased to be nonsparking, except devices: OHAAE, AT-5738A1, A2 OHAAE, AT-5739A1, A2	
12.2 (Rev 2)	II.6		12.2.1
	ANSI N237-1976; typical long term concentrations of principal radionuclides in fluid steams.	GE developed source terms from operating experience.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
12.3 - 12.4 (Rev 2)	II.17		12.3.4.1.3
	ANSI/ANS-HPSSG-6.8.1-1981: Criteria for location and and design of area radiation monitoring systems.	Location of fixed continuous area gamma radiation monitors are not in agreement with this ANSI/ANS standard.	
	II.4.b.3		
	Ventilation monitors are to be upstream of HEPA filters.	Ventilation monitors are downstream of HEPA filters.	
	II.4.a.3		
	The area radiation monitors should provide on-scale readings for normal and anticipated operational occurrences and accidents.	Not all radiation monitors have on-scale reading ranges designed to account for post accident conditions.	
	II.4.a.8 and 4.b.7		
	Criteria imply that radiation monitoring systems be on emergency power.	Radiation monitors installed at HCGS are not on emergency power.	
	II.4.e		
	Compliance to the criteria of 10 CFR 70.24 for accidental criticality monitor	Based upon NRC evaluation of the information presented in the Hope Creek Special Nuclear Material (SNM) License application dated May 23, 1985, PSE&G has been granted exemption to the requirements of 10 CFR 70.24 as documented in Hope Creek SNM License No. 1953 dated August 21, 1985. When the Special Material License expired, the exemption Conditions were incorporated into the Operating License in SSER 5. These conditions are specific to GE fuel only. Alternately, 10CFR50.68 can be used to demonstrate compliance with 10CFR70.24. both of these approaches eliminate the need for instrumentation since criticality is not credible.	

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
13.6 (Rev 2)	II		13.6
	Regulatory Guide 5.20 sets requirements for security personnel training program.	Security personnel training program will be based on Appendix B to 10 CFR Part 73, to the extent applicable to power reactors.	
14.2 (Rev 2)	II		14.2.13.1, 2, 3, 4, and 5
	Conformance to Regulatory Guides 1.68, 1.20, 1.56, 1.68.3 and 1.10.8 (Page 14.2-3, 4)	Nonconformance, in part, with Regulatory Guides 1.68, 1.20, 1.56, 1.68.3 and 1.108.	
15.3.3 - 15.3.4 (Rev 1)	II.10		15.3.4.6
	Assumptions for coolant pumps rotor seizure and coolant pump shaft break accident.	Turbine trip with coincidental loss of offsite power and coast down of undamaged pumps is not assumed.	
15.8 (Rev 1)	II.a		15.8.4
	Application of GDC 10 to the ATWS event.	GDC 10 is not applied.	
	II.b		
	Application of GDC 15 to the ATWS event.	GDC 15 is not applied.	
	II.c		
	Application of GDC 26 to the ATWS event.	GDC 16 is not applied.	
	II.d		
	Application of GDC 27 to the ATWS event.	GDC 27 is not applied.	

TABLE 1.11-1 (Cont)

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Differences	FSAR Section(s) Where Discussed
	II.e		
	Application of GDC 29 to the ATWS event.	GDC 29 is not applied.	
	II.f		
	Criteria of NUREG-0460, Vol. 2, Section IV-4 apply to BWR RPT.	Criteria j of NUREG-0460, Vol. 2, Section IV-4 is not applied.	

1.12 UNRESOLVED GENERIC SAFETY ISSUES

1.12.1 Introduction

The Nuclear Regulatory Commission (NRC) continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources, including experience from operating reactors; research results; NRC staff and Advisory Committee on Reactor Safeguards (ACRS) safety reviews; and vendor, architect/engineer, and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to ensure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to ensure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, e.g., modifications to operating procedures, may be sufficient to allow further study of the issue before making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called generic safety issues, because they are related to a particular class or type of nuclear facility rather than to a specific plant. Certain of these issues have been designated as unresolved safety issues in NUREG-0410, NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants, dated January 1, 1978. However, as discussed above, such issues are considered on a generic basis only after the NRC staff has made an initial determination that the safety significance of the issue does not prohibit continued operation, or require licensing actions while the longer-term generic review is underway.

In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program.

The review is described in a report, NUREG-0510, Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress, dated January 1979. The report provides the following definition of an unresolved safety issued:

> An unresolved safety issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plant it affects.

Furthermore, the report indicates that, in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary either to compensate for a possible major reduction in the degree of protection of the public health and safety, or to provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an unresolved safety issue is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition, as described in NUREG-0510. As a result, 17 unresolved safety issues addressed by 22 tasks in the NRC program were identified. The issues and applicable task numbers are listed below. Progress on these issues was first discussed in the 1978 NRC Annual Report. Each number of each generic task, e.g., A-1, in the NRC program addressing each of the 17 issues, is indicated in parentheses following the title:

1. Waterhammer (A-1)

2. Asymmetric blowdown loads on the Reactor Coolant System (A-2)

3. Pressurized water reactor steam generator tube integrity (A-3, A-4, A-5)

4. BWR Mark I and Mark II pressure suppression containments (A-6, A-7, A-8, A-39)

5. Anticipated transients without scram (A-9)

6. BWR nozzle cracking (A-10)

7. Reactor vessel materials toughness (A-11)

8. Fracture toughness of steam generator and reactor coolant pump supports (A-12)

9. Systems interaction in nuclear power plants (A-17)

10. Environmental qualification of safety-related electrical equipment (A-24)

11. Reactor vessel pressure transient protection (A-26)

12. Residual heat removal requirements (A-31)

13. Control of heavy loads near spent fuel (A-36)

14. Seismic design criteria (A-40)

15. Pipe cracks at boiling water reactors (A-42)

16. Containment emergency sump reliability (A-43)

17. Station blackout (A-44).

Six of the 22 tasks identified with the unresolved safety issues are not applicable to Hope Creek Generating Station (HCGS), because they apply to pressurized water reactors only. These tasks are A-2, A-3, A-4, A-5, A-12, and A-26. Task A-8 only applies to Mark II boiling water reactor (BWR) containments. With regard to the remaining 15 tasks that are applicable to HCGS, the NRC staff has issued NUREG reports providing its resolution of eight of the issues. These issues are as follows:

Task Number	NUREG Report No. and Title
A-6	NUREG-0408, Mark I Containment Short-term Program Safety Evaluation Report
A-9	NUREG-0460, Vol 4, Anticipated Transients Without Scram for Light Water Reactors
A-10	NUREG-0619, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking
A-24	NUREG-0588, Revision 1, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment
A-31	NUREG-0800, SRP 5.4.7 and BTP 5-1, Residual Heat Removal Systems (incorporate requirements of USI A-31)
A-36	NUREG-0612, Control of Heavy Loads at Nuclear Power Plants
A-39	NUREG-0661 Mark I Containment Long-Term Program Safety Evaluation Report

Task Number	NUREG Report No. and Title
A-42	NUREG-0313, Revision 1, Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping.

The extent of implementation of these guidelines into the HCGS design is demonstrated by discussions in the following sections:

1. Appendix 3B - On the primary containment analysis (A-6), (A-39)

2. Section 3.11 - On environment design of mechanical and electrical equipment (A-24)

3. Section 4.6.1.2.4 - On the control rod drive hydraulic system (A-10) General Electric, Boiling Water Reactor Feedwater Nozzle/Sparger Final Report, NEDE-21821-02, August 1979

4. Section 5.2.3 - On RCPB materials (A-42)

5. Section 5.4.7 - On residual heat removal (A-31)

6. Section 9.1.5 - On the handling of overhead heavy loads (A-36)

7. Section 15.8 - On anticipated transient without scram (A-9).

The remaining issues applicable to HCGS are:

1. Waterhammer (A-1)

2. Mark I containment long term program (A-7)

3. Reactor vessel materials toughness (A-11)

4. Systems interaction in nuclear power plants (A-17)

5. Seismic design criteria (A-40)

6. Containment emergency sump reliability (A-43)

7. Station blackout (A-44).

1.12.2 New Unresolved Safety Issues

The NRC has performed an in-depth and systematic review of generic safety concerns identified since January 1979 to determine if any of these issues should be designated as new unresolved safety issues. The candidate issues originated from concerns identified in NUREG-0660, titled NRC Action Plan as a Result of the TMI-2 Accident; ACRS recommendations; abnormal occurrence reports; and other operating experience. The NRC considered the above information and approved the following four new unresolved safety issues:

1. Shutdown decay heat removal requirements (A-45)

2. Seismic qualification of equipment in operating plants (A-46)

3. Safety implication of control systems (A-47)

4. Hydrogen control measures and effects of hydrogen burns on safety equipment (A-48).

A description of the above process, together with a list of the issues considered, is presented in NUREG-0705, Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants, Special Report to Congress, dated March 1981. An expanded discussion of each of the new unresolved safety issues is also contained in NUREG-0705.

Recently, Task A-49, Pressurized Thermal Shock, was identified as an unresolved safety issue. Although the NRC staff has not determined the extent of this issue, it is not expected to affect boiling water reactors (BWRs).

1.12.3 Discussions of Tasks as They Relate to HCGS

This section provides HCGS evaluation of each applicable unresolved safety issue.

1.12.3.1 Task A-1, Waterhammer

1. Issue - Waterhammer events are intense pressure pulses in fluid systems caused by any one of a number of mechanisms and system conditions, such as rapid condensation of steam pockets, steam-driven slugs of water, pump startup with partially empty lines, and rapid valve motion. Since 1971, over 200 incidents involving waterhammer in pressurized and boiling water reactors have been reported. The waterhammers (or steam hammers) have involved steam generator feedrings and piping; the Residual Heat Removal (RHR) Systems; Emergency Core Cooling Systems (ECCS); and containment spray, service water, feedwater, and steam lines.

   Most of the damage reported has been relatively minor, involving pipe hangers and restraints; however, several waterhammer incidents have resulted in piping and valve damage. The most serious waterhammer events have occurred in the steam generator feedrings of pressurized water reactors. In no case has any waterhammer incident resulted in the release of radioactive material.

   Under generic Task A-1, the potential for waterhammer in various systems is being evaluated and appropriate requirements and systematic review procedures are being developed to ensure that waterhammer is given appropriate consideration in all areas of licensing review. A technical report, NUREG-0582, Waterhammer in Nuclear Power Plants (July 1979), providing the results of an NRC staff review of waterhammer events in nuclear power plants and stating current staff licensing positions, completes a major subtask of generic Task A-1.

2. HCGS discussion - Although waterhammer can occur in any light water reactor, and approximately 118 actual and probable events have been reported in boiling water reactors (BWRs) as of September 1979, none has caused major pipe failures in a BWR such as HCGS, and none has resulted in the offsite release of radioactivity. As noted above, the most severe waterhammers observed to date have been in steam generators. The HCGS feedwater design includes the relevant design provisions that have been effective in eliminating the occurrence, and lessening the severity of, waterhammer in PWRs. The HCGS feedwater ring is designed to incorporate use of only short horizontal runs of feedwater pipe into the reactor pressure vessel and use of J-tubes.

   Furthermore, any waterhammer that may occur in feedwater or main steam piping will not impair the ECCS, because ECCS water can enter the reactor vessel through six separate reactor vessel nozzles independent of the feedwater and main steam piping.

   To protect the HCGS ECCS from the effects of waterhammer, there is an ECCS discharge line fill network whose pumps take suction from the suppression pool or the condensate storage tank (CST), and provide water to the ECCS injection lines. This ensures that the ECCS lines remain filled with water, the ECCS pumps will not start pumping into voided lines, and steam will not collect in the ECCS piping.

Piping design codes require consideration of impact loads. A systematic review of all safety and nonsafety systems has been performed. Where waterhammer problems were identified, design refinements were implemented to address the specific problem. Some of the design refinements incorporated to address waterhammer are listed below:

a. Increasing valve closure times

b. Changing piping layout to preclude water slugs in steam lines and vapor formation in water lines

c. Adding snubbers and pipe hangers

d. Using vents and drains

e. The use of accumulators.

For specific discussion of the ECCS discharge line fill network, see Section 6.3.2.2.6.

In the event that Task A-1 identifies potentially significant waterhammer scenarios that have not been accounted for explicitly in the design and operation of HCGS, corrective measures will be implemented at that time. The task has not identified the need for measures beyond those already implemented.

Based on the foregoing, PSE&G concludes that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.2 Task A-7, Mark I Containment Long-Term Program

1. Issue - During the conduct of a large scale testing program for an advanced design pressure suppression containment system (Mark III) for BWRs, new suppression

pool hydrodynamic loads associated with a postulated loss-of-coolant accident (LOCA) were identified that had not been explicitly included in the original design of the Mark I containment systems. In addition, experience at operating plants has indicated that the dynamic effects of safety/relief valve (SRV) discharges to the suppression pool could be substantial and should be reconsidered.

The results of the Mark I containment short-term program (STP) have ensured that for a "most probable load" the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated LOCA. The need exists both to establish design basis LOCA loads that are appropriate for the life of the facility, and either to restore the originally intended design safety margins for the containment systems or to ensure that adequate design safety margins have been provided in the design of the containment system prior to issuance of an operating license.

The Mark I Owner's Group has initiated a comprehensive testing and evaluation program to define design basis loads for the Mark I containment system and to establish structural acceptance criteria that will ensure margins of safety for the containment system that are equivalent to those currently specified in the ASME B&PV Code. Also included in their program is an evaluation of the need for structural modifications and/or load mitigation devices to ensure adequate Mark I containment system structural safety margins.

The NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owner's Group prior to the conduct of plant-unique structural evaluations. The results of this evaluation will be documented in a generic safety evaluation report. Publication of this report will constitute the resolution of this technical activity.

Implementation of the results of this generic review, although not a part of this task, will be accomplished by an NRC requirement that each affected utility perform a plant-unique structural evaluation of the containment system for their facility using the loads, loading combinations, and structural acceptance criteria approved by the NRC staff.

2. HCGS discussion - At HCGS, this unresolved safety issue is considered complete. HCGS is proceeding according to the guidelines of NUREG-0661. For discussion of the primary containment plant unique analysis, see Appendix 3B.

   Therefore, PSE&G concludes that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.3 Task A-11, Reactor Vessel Materials Toughness

1. Issue - Resistance to brittle fracture is described quantitatively by a material property generally denoted as fracture toughness. Fracture toughness has different values and characteristics depending on the material being considered. For steels used in a nuclear reactor pressure vessel (RPV), three considerations are important:

   a. Fracture toughness increases with increasing temperature

   b. Fracture toughness decreases with increasing load rates

   c. Fracture toughness decreases with neutron irradiation.

In recognition of these considerations, power reactors are operated within restrictions imposed by the Technical Specifications on the pressure during heatup and cooldown operations. These restrictions ensure that the reactor vessel will not be subject to a combination of pressure and temperature that could cause brittle fracture of the vessel if there were significant flaws in the vessel material. The effect of neutron radiation on the fracture toughness of the vessel material over the life of the plant is accounted for in Technical Specification limitations.

The principal objective of Task A-11 is to develop safety criteria to allow a more precise assessment of safety margins during normal operation, transients, and accident conditions in older reactor vessels with marginal fracture toughness. When Task A-11 is completed and explicit fracture evaluation criteria for accident conditions are defined, all vessels will be reevaluated for acceptability over their design lives.

2. HCGS discussion - Based on its evaluation of the HCGS reactor vessel materials toughness, PSE&G concludes that adequate safety margins exist for brittle failure for postulated accidents throughout HCGS's design life.

   A major condition necessary for full compliance to 10CFR50, Appendix G, is satisfaction of the requirements of the Summer 1972 addenda to ASME B&PV Code, Section III. As explained in Section 5.3.1.5, this is not entirely possible with components that were purchased to earlier code requirements. The extent of compliance is discussed in Appendix 5A. Compliance with the toughness requirements described in Appendix 5A and the operating limitations on pressure and temperature based on fracture margins in Appendix G assure adequate safety margins against brittle fracture. The extent of compliance to 10CFR50, Appendix H, is also discussed in Appendix 5A.

Therefore, PSE&G concludes that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.4 Task A-17, Systems Interaction in Nuclear Power Plants

1. Issue - The staff's systems interaction program was initiated in May 1978 with the definition of unresolved safety issue A-17, System Interaction in Nuclear Power Plants, and was intensified by TMI Action Plan (NUREG-0660) Item II.C.3, Systems Interaction. The concern arises because the design, analysis, and installation of systems are frequently the responsibility of teams of engineers with functional specialities such as civil, electrical, mechanical, or nuclear. Experience at operating plants has led to questions of whether the work of these functional specialists is sufficiently integrated to enable them to minimize adverse interactions among systems. Some adverse events that occurred in the past might have been prevented if the teams had ensured the necessary independence of safety systems under all conditions of operation.

2. HCGS discussion - The NRC staff's current procedures assign primary responsibility for review of various technical areas to specific organizational units and assign secondary responsibility to other units where there is a functional interface. Designers follow somewhat similar procedures and provide the analyses of systems and interface reviews. Task A-17 has been developing methods that could identify adverse systems interactions that were not considered by current review procedures. The first phase of this study began in May 1978, and was completed in February 1980, by Sandia Laboratories under contract to the NRC staff.

The phase I investigation was structured to identify areas where interactions are possible between systems that have the potential of negating or seriously degrading the performance of safety functions. The study concentrated on commonly caused failures among systems that would violate a safety function. The investigation was to then identify those areas in which NRC review procedures may not have properly accounted for these interactions.

The Sandia Laboratories used fault-tree analysis on a selected light water reactor (LWR) design to identify component failure combinations, cut sets, that could result in loss of a safety function. The cut sets were further reduced by incorporating six linking systems failures into the analysis. The results of the Sandia effort indicated a few potentially adverse systems interactions within the limited scope of the study. The staff reviewed the interactions for safety significance and generic implications. The staff concluded that no corrective measures needed to be implemented immediately, except for the potential interaction between the power-operated relief valve and its block valve. This interaction had been separately identified by the evaluations of the TMI-2 accident while Sandia was studying the selected LWR. Because corrective measures were already being implemented, no separate measures were needed under unresolved safety issue A-17.

NUREG-0660 provides for a systems interaction study in Item II.C.3, Systems Interactions. Since April 1980, the Office of Nuclear Reactor Regulation has intensified the effort both by broadening the study of methods to identify potential systems interactions and by preparing guidance for audit reviews of selected plants for systems interactions.

It is expected that the development of systematic ways to identify, rank, and evaluate systems interactions will go further to reduce the likelihood of intersystem failures, resulting in the loss of plant safety functions. A comprehensive program is expected to use analytical methods, visual inspections, experience feedback, and simulator dependencies experiments. The LWR industry's current experience with systems interaction reviews is fragmented. Experience like that gained by the Phase I study is an essential ingredient to the staff's considerations of a comprehensive systems interaction program.

The design of HCGS is based on the principle of defense in depth. Adherence to this principle results in requirements such as physical separation and independence of redundant safety systems, and protection against hazards such as high energy line ruptures, missiles, high winds, flooding, seismic events, fires, human factors, and sabotage. These design provisions are subject to interdisciplinary reviews of safety-grade equipment and address different types of potential systems interactions. Also, the quality assurance program that is followed during the design, construction, and operational phases for HCGS contributes to the prevention of introducing adverse systems interactions. Interdisciplinary reviews and the HCGS quality assurance program provide assurance that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.5 <u>Task A-40, Seismic Design Criteria/Short Term Program</u>

1. Issue - NRC regulations require that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are

provided in the NRC regulations and in regulatory guides issued by the NRC. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance existed. For this reason, reviews of the seismic design of various plants are being undertaken again by the NRC to ensure that these plants do not present an undue risk to the public. Task A-40 is, in effect, a compendium of short term efforts to support such reevaluation efforts of the NRC staff, especially those related to older operating plants. Should the resolution of Task A-40 indicate that a change is needed in these licensing requirements, all reactors, including HCGS, will be reevaluated on a case-by-case basis.

2. HCGS discussion - The seismic design basis and seismic design of HCGS are in accordance with current requirements and regulations as discussed in Section 3.

Accordingly, PSE&G has concluded that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.6 <u>Task A-43, Containment Emergency Sump Reliability</u>

1. Issue - Following a postulated LOCA, that is, a break in the Reactor Coolant System (RCS) piping, the water flowing from the break would be collected in the suppression pool. This water would be recirculated through the reactor system by the emergency core cooling pumps to maintain core cooling. This water may also be circulated through the Containment Spray System to remove heat and fission products from the drywell and wetwell atmosphere. Loss of the ability to draw water from the suppression pool could disable the emergency cooling and containment spray systems.

2. HCGS discussion - The concern addressed by this task for BWRs is limited to the potential for degraded Emergency Core Cooling System (ECCS) performance as a result of thermal insulation debris that may be blown into the suppression pool during a LOCA and cause blockage of the pump suction lines.

The likelihood of any insulation being drawn into an ECCS pump suction line is very small, as discussed in Section 6.2.2.2. The potential debris in the drywell could only be swept into the suppression pool through the downcomer openings, which are covered by deflector plates. Most pieces reaching the pool would tend to either float to the surface or settle on the bottom, and would not be drawn into the pump suction, because the suction centerline is above the pool bottom and below the pool surface. In addition, the HCGS design employs strainers on the suction piping, and net positive suction head calculations for the pumps are based on 50 percent blockage.

A second concern, potential vortex formation, is not considered serious for Mark I containments because of the depth of the ECCS suction lines, the low approach velocities, and the strainer configuration.

Accordingly, PSE&G concludes that HCGS can be operated without undue risk to the health and safety of the public.

1.12.3.7 Task A-44, Station Blackout

Task A-44, Station Blackout was resolved by the NRC by issuance of an amendment to Title 10 of the Code of Federal Regulations on July 21, 1988. This amendment added Section 10 CFR 50.63, "Loss of All Alternating Current Power," (Station Blackout) to the Code of Federal Regulations. Conformance to 10 CFR 50.63 is discussed in Section 1.15.1.

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1.12.3.8 Task A-45, Shutdown Decay Heat Removal Requirements

1. Issue - Following a reactor shutdown, the radioactive decay of fission products continues to produce heat (decay heat) that must be removed from the primary system. The principal means for removing this heat in a BWR while at high pressure is by means of the steam lines to the main condenser. The condensate is normally returned to the reactor vessel by the feedwater system; in addition, the steam turbine driven RCIC system is provided to maintain primary system inventory if ac power is not available. When the system is at low pressure, the decay heat is removed by the Residual Heat Removal (RHR) System. This unresolved safety issue will evaluate the benefit of providing alternate means of decay heat removal, which could substantially increase the plant's capability to handle a broader spectrum of transients and accidents. The study will consist of a generic system evaluation and will result in recommendations regarding: 1) the desirability of and possible design requirements for improvements in existing systems, or 2) an alternative decay heat removal method if the improvement or alternative can significantly reduce the overall risk to the public.

   Following the TMI-2 accident, the industry performed and documented extensive analyses of feedwater transients and small break LOCAs to support acceptability of current designs. A report of these analyses for GE BWRs was provided to the NRC in NEDO-24708A, Revision 1, dated December 1980. The staff's assessment of current designs related to loss of feedwater transients and small LOCAs is contained in NUREG-0626, Generic Evaluation of Feewater Transients and Small Break Loss-of-Coolant Accidents in GE-Designed Operating Plants and Near-Term Operating License Applications.

2. HCGS discussion - The HCGS reactor has various methods for removal of decay heat. As discussed above, when the reactor is at high pressure and temperature, decay heat is normally rejected to the main condenser and condensate returned to the vessel by the feedwater system. At lower temperatures and pressures, the RHR system is used in the shutdown cooling mode, which consists of two virtually redundant loops.

   If the main condenser is unavailable, heat can be removed by means of the main steam safety/relief valves (SRVs) to the suppression pool. The suppression pool can then be cooled by using redundant loops of the RHR system in the suppression pool cooling mode.

   The RCIC system, which is a safety grade Engineered Safety Feature (ESF) System, provides an alternative means of supplying makeup water to the vessel. The turbine driven pump in the RCIC system takes suction from the condensate storage tank or suppression pool and pumps to the vessel. The HPCI system is provided in the unlikely event that the RCIC system is unavailable.

   Another alternative for cooling and supplying makeup water is to manually open the Automatic Depressurization System (ADS) valves and to use the RHR system. Two of the four RHR loops are available for use in the suppression pool cooling mode and two of the four loops are available to pump water into the reactor vessel. Only one loop is required for pumping water into the reactor and only one for suppression pool cooling. The other two loops are redundant.

   In addition, any one of the four core spray pumps can be used to pump water into the vessel, allowing the RHR system to be used exclusively in the suppression pool cooling mode.

See Sections 5.4.7 and 15.9.6.3.3 for further discussion of decay heat removal failure modes.

On the basis of the above considerations, PSE&G has concluded that HCGS can be operated before the ultimate resolution of this generic issue without undue risk to the health and safety of the public.

1.12.3.9 Task A-46, Seismic Qualification of Equipment in Operating Plants

1. Issue - The design criteria and methods for the seismic qualification of mechanical and electrical equipment in nuclear power plants have undergone significant change during the course of the commercial nuclear power program. Consequently, the margins of safety provided in existing equipment to resist seismically induced loads and perform the intended safety functions may vary considerably. Therefore, the seismic qualification of the equipment in operating plants must be reassessed to ensure the ability to bring the plant to safe shutdown conditions when subject to a seismic event. The objective of this unresolved safety issue is to establish an explicit set of guidelines that could be used to judge the adequacy of the seismic qualification of mechanical and electrical equipment at all operating plants instead of attempting to backfit current design criteria for new plants. This guidance will concern equipment required to safely shut down the plant, as well as equipment whose function is not required for safe shutdown but whose failure could result in adverse conditions that might impair shutdown functions.

2. HCGS discussion - HCGS is designed using current seismic design criteria, as discussed in Section 3. All HCGS systems, components, and equipment related to plant safety are designed to withstand safe shutdown and operating

basis seismic events. Therefore, PSE&G has concluded that HCGS can be operated without undue risk to public health and safety.

1.12.3.10 Task A-47, Safety Implications of Control Systems

1. Issue - This issue concerns the potential for transients or accidents being made more severe as a result of control system failures or malfunctions. These failures or malfunctions may occur independently or as a result of the accident or transient under consideration. One concern is the potential for a single failure, such as loss of a power supply, short circuit, open circuit, or sensor failure to cause simultaneous malfunction of several control features. Such an occurrence could conceivably result in a transient more severe than those transients analyzed as anticipated operational occurrences. A second concern is for a postulated accident to cause control system failures that would make the accident more severe than analyzed. Accidents could conceivably cause control system failures by creating a harsh environment in the area of the control equipment or by physically damaging the control equipment. Although it is generally believed that such control system failures would not lead to serious events or result in conditions that safety systems cannot safely handle, in-depth studies have not been rigorously performed to verify this belief. The potential for an accident that would affect a particular control system, and effects of the control system failures, may differ from plant to plant. Therefore, it is not possible to develop generic answers to all of these concerns; it is possible to develop generic criteria that can be used for future plant specific reviews. The purpose of this unresolved safety issue is to verify the adequacy of existing criteria for control systems or propose additional generic criteria, if necessary, that will be used for plant-specific review.

2. HCGS discussion - The HCGS safety systems have been designed with the goal of ensuring that control system failures will not prevent automatic or manual initiation and operation of any safety system equipment required to trip the plant or to maintain the plant in a safe shutdown condition following any anticipated operational occurrence or accident. This has been accomplished by providing both independence between safety and nonsafety grade systems and isolating devices between safety and nonsafety grade systems. These devices preclude the propagation of nonsafety grade system equipment faults so that operation of the safety grade system equipment is not impaired.

   The subtask of this issue concerning the reactor overfill transient in boiling water reactors is currently under review by the BWR Owner's Group, of which PSE&G is a member. Pending ultimate resolution of this item, PSE&G has incorporated, in the HCGS design, a high level trip (Level 8) of the RCIC, and feedwater systems to prevent the occurrence of overfill transients.

   On the basis of the above considerations, PSE&G has concluded that there is reasonable assurance that HCGS can be constructed and operated without undue risk to the health and safety of the public.

1.12.3.11 <u>Task A-48, Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment</u>

1. Issue - Following a LOCA in an LWR plant, combustible gases, principally hydrogen, may accumulate inside the primary reactor containment as a result of the following:

   a. Metal water reaction involving the fuel element cladding

b. The radiolytic decomposition of the water in the reactor core and the containment sump

c. The corrosion of certain construction materials by the spray solution

d. Any synergistic chemical, thermal, and radiolytic effects of post-accident environmental conditions on containment protective coating systems and electric cable insulation.

Because of the potential for significant hydrogen generation as the result of an accident, 10CFR50.44, Standards for Combustible Gas Control System in Light Water Cooled Power Reactors, and GDC 41, Containment Atmosphere Cleanup, in Appendix A to 10CFR50, require that systems be provided to control hydrogen concentrations in the containment atmosphere following a postulated accident, to ensure that containment integrity is maintained.

Regulation 10CFR50.44 requires that the combustible gas control system provided be capable of handling the hydrogen generated as a result of degradation of the ECCS, so that the hydrogen release is five times the amount calculated in demonstrating compliance with 10CFR50.46, or the amount corresponding to reaction of the cladding to a depth of 0.00023 in., whichever amount is greater.

The accident at TMI-2 on March 28, 1979 resulted in hydrogen generation well in excess of the amounts specified in 10CFR50.44. As a result of this, it became apparent to the NRC that specific design measures are needed for handling larger hydrogen releases, particularly for small, low pressure containments. As a result, the NRC determined that a rulemaking proceeding should be undertaken to define the manner and extent to which hydrogen evolution and other effects of a degraded core need to be taken into account in plant design. An advance notice of this rulemaking proceeding on degraded core issues was published in the Federal Register on October 2, 1980.

Recognizing that a number of years may be required to complete this rulemaking proceeding, a set of short term or interim actions relative to hydrogen control requirements was developed and implemented. These interim measures were described in a second October 2, 1980, Federal Register notice.

2. HCGS discussion - HCGS is committed to inerting the primary containment with nitrogen gas during power operation in order to preclude hydrogen burning, as discussed in Section 6.2.5. To ensure that the hydrogen concentration in the primary containment is maintained below the lower flammability limit, a combustible gas analyzer subsystem is provided as part of the containment atmospheric control system.

The results of PSE&G's evaluation indicate that HCGS can be operated without undue risk to the public health and safety.

1.13 SYMBOLS AND TERMS

1.13.1 Text Acronyms

Acronyms used throughout the Final Safety Analysis Report (FSAR) are listed in Table 1.13-1.

1.13.2 Logic Symbols

Logic symbols used on functional control diagrams (FCD) are shown in Figure 1.13-2.

1.13.3 Piping Identification

Piping is identified on the piping and instrumentation diagrams (P&IDs) by a three group identifier where the first group is the nominal pipe size in inches; the second is a three letter group for the pipe class; and the third is a three digit group sequentially assigned within a pipe class.

Example:

```
                                    6"    HBD   116
                                    |      |     |
Size -------------------------------|      |     |
                                           |     |
Class -------------------------------------|     |
                                                 |
Sequence ----------------------------------------|
```

The three letter group for the pipe class is described in detail in Table 1.13-2.

The three digit sequence number is assigned consecutively from 001 to 999.

Line identification, for lines other than those of a major system on a P&ID, is shown with the applicable system designation preceding the line identification, e.g., AF-6"-HBD-116. In some cases, this identifier is preceded by a 0 or 1 to indicate Common or Unit 1, respectively.

1.13.4 Valve Identification

All manual and remotely operated valves have unique identification numbers for tracking purposes and are shown in the P&IDs. Listed below are the numbering systems used for each group of valves. Self-actuated devices and solenoid valves are identified as shown on Plant Drawing M-00-0. All other valves, including those which have a General Electric (GE) Master Parts List (MPL) number and those valves supplied by vendors as part of an equipment package and not installed by Bechtel, are identified by the prefix letter "V" followed by a three digit sequence number. In some cases, this identifier is preceded by a 1 or 0 to indicate Unit 1 or Common, respectively.

Remote operated valves that do not have a GE MPL number are also identified by the two-letter prefix HV- followed by a three or four digit sequence number. Those valves in GE's MPL are identified by the two-letter prefix HV followed by the GE valve number, e.g., HV-F055.

Valve identification, for valves other than those of the major system on a P&ID, is shown with the applicable system designator preceding the valve number, e.g., AP-V126.

Valve types are indicated on Plant Drawing M-00-0. Valves that are not numbered are supplied as part of a vendor mounted equipment package are identified in the vendor's operation and maintenance manuals. This is done to avoid duplication in numbering these valves.

1.13.5 Equipment Numbering and Location

Equipment is identified on the P&IDs by a four group identifier as discussed below:

Example:

```
                                              1  A - P  101

Unit number ------------------------------------------
1 - Unit 1

Number of items ------------------------------------------
(lettered alphabetically if
more than one item; a zero (0)
is used if only one item)

Equipment classification ------------------------------------
(See description below)

Sequence number -----------------------------------------------------
(See description below)
```

Equipment classification is identified by type as follows:

A 7.2-kV or 4.16-kV switchgear (NA=test station)

B 480 V unit substation, MCC or distribution panel

C Control boards

D DC equipment

E Heat exchangers

F Filters and cleaning equipment

FH Fuel handling equipment

G Generators (turbine, diesel) and associated equipment

H Hoists, cranes

HC Hose rack in cabinet (H_2O)

HO Hose reel (CO_2) (CO_2 hose reels are removed from the plant)

HR Hose reel (H_2O)

J 120 V ac instrument power distribution panels

K Air compressors, chiller compressors

L Lighting panels

N Local control station

P Pumps

R Equipment in switchyard

S Miscellaneous

T Tanks and pressure vessels

U Hydraulic control units

V Air conditioning units, ventilation fans and exhausters, process fans and blowers.

VE HVAC heat exchangers, unit heaters

VH HVAC ventilation housing, air handling units

W	Electrical penetrations
X	Transformers
Y	120 V ac power distribution panels
Z	Computer equipment

The three digit sequence number is assigned consecutively to identify specific equipment as follows:

000-099	NSSS local panels and racks
100-199	Turbine Building
200-299	Reactor Building
300-399	Auxiliary Building, radwaste area
400-499	Auxiliary Building, control and diesel areas
500-599	Miscellaneous locations - outside power block
600-649	NSSS control room panels (except 642 & 643)
650-749	Balance of plant (BOP) control room panels (including 642 & 643)
800-899	Annunciator panels (corresponds to 600 series panels)
900-999	Miscellaneous locations inside power block

1.13.6 Electrical Component Identification

This section describes the methods used to identify electrical equipment locations and to number electrical schemes, cables, and raceways.

1.13.6.1 Equipment Location Numbers

Each piece of electrical equipment is identified by an equipment number as described in Section 1.13.4. To facilitate cable routing from one equipment location to another, a location number is also assigned to each piece of electrical equipment. Generally, the equipment number and equipment location number for a specific piece of electrical equipment are identical. For large pieces of electrical equipment, such as switchgear, load centers, and motor control centers (MCC), which are compartmentalized, the equipment location number consists of the basic equipment number plus additional suffixed information to identify a location within the equipment itself. The following two examples illustrate equipment location numbers:

Example 1: 10X101
Example 2: 10B44601

In the first example, the equipment number and equipment location number for transformer 10X101 are identical. In the second example, the basic MCC equipment location number 10B446 is suffixed to establish an equipment location number, 10B44601, which identifies a specific cubicle within the MCC.

Equipment location numbers are generally assigned to items listed in the circuit and raceway schedules. Accordingly, most electrical equipment related to systems such as lighting, communications, and cathodic protection is not included.

Electrical equipment that is an integral part of mechanical equipment is assigned the same number as the mechanical equipment.

1.13.6.2 Scheme Cable Numbers

Each cable in the plant is uniquely identified by a scheme cable number that is composed of nine characters of the form LLNLNNNNL. The example given below illustrates what each character of a cable symbolizes.

A P 1 Q 08 01 R

Cable 'R' in cable Block Diagram

Scheme Number (01)

System (RHR System)

System Q - In This Case Nuclear Steam Supply System

Plant Unit Number

System Voltage Level

Separation Group

Except for cabling associated with the plant lighting and cathodic protection systems, each cable in the plant is identified by a cable number.

1.13.6.3 Raceway Numbers

A unique alpha-numeric identification is assigned to each cable tray, conduit pull box, sleeve, or slot for cables, etc. This identification consists of 8 characters that are indicated on electrical raceway drawings.

The cable tray numbering system is illustrated in the following example.

1 3 A T F E 01

- 01 — Tray Subsection Number
- E — Building Elevation
- F — Voltage Level
- T — Tray
- A — Separation Group
- 3 — Plant Building and Area
- 1 — Plant Unit Number

1.13.6.4 Conduit Numbers

The conduit numbering system is illustrated in the following example.

```
1   4   N   R   P   E   34
|   |   |   |   |   |   |
|   |   |   |   |   |   |____________ Sequential Number
|   |   |   |   |   |
|   |   |   |   |   |________________ Elevation
|   |   |   |   |
|   |   |   |   |____________________ Service (control or power)
|   |   |   |
|   |   |   |________________________ Conduit
|   |   |
|   |   |____________________________ Separation Group
|   |
|   |________________________________ Building and Area
|
|____________________________________ Plant Unit Number 1
```

TABLE 1.13-1

ACRONYMS USED IN FSAR

ABA	Amplitude Based Algorithm
ABDA	auxiliary Building, diesel area
ABCA	auxiliary Building, control area
ACRS	Advisory Committee on Reactor Safeguards
ADS	Automatic Depressurization System
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	as low as is reasonably achievable
ANI	American Nuclear Insurers
ANS	American Nuclear Society
ANSI	American National Standards Institute
APRM	average power range monitor
ARI	alternate rod insertion
ARMS	Area Radiation Monitoring System
ARW	high conductivity radwaste
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASME B&PV Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ASTM	American Society for Testing and Materials
ATM	analog trip module
ATWS	anticipated transients without scram
AWS	American Welding Society
AWWA	American Water Works Association
BISIS	bypassed and inoperable status indication
BOC	beginning of cycle
BOP	balance of plant
BTP	Branch Technical Position
BWR	boiling water reactor

CACWS	Control Area Chilled Water System
CAE	control area exhaust
CDA	Confirmation Density Algorithm
CERS	control equipment room supply
CFR	Code of Federal Regulations
CHRS	Containment Hydrogen Recombiner System
CIPS	Containment Inerting and Purge System
CPCS	Containment Prepurge Cleanup System
CPPU	Constant Pressure Power Uprate
CPR	critical power ratio
CRD	control rod drive
CRDA	control rod drop accident
CRDHS	Control Rod Drive Hydraulic System
CREF	control room emergency filter
CRIDS	Control Room Integrated Display System
CRPIS	Control Rod Position Indication System
CRRA	control room return air
CRS	control room supply
CRT	cathode ray tube
CRW	clean radwaste
CSCM	containment spray cooling mode
CSR	cable spreading room
CST	condensate storage tank
CVN	Charpy V-notch
CWS	Circulating Water System
DABE	diesel area battery room exhaust
DAPRS	diesel area panel room supply
DBA	design basis accident
DBE	design basis event
DCR	design change request
DCRMS	document control records management system
DECRW	decontamination radwaste
DIDA	Defense-in-Depth Algorithm
DOP	dioctyl phthalate
DRR	diesel generator room recirculation
DRW	dirty radwaste
DSS-CD	Detect and Suppress Solution – Confirmation Density

EAB	exclusion area boundary
EACS	Equipment Area Cooling System
EAS	essential auxiliary support
ECCS	Emergency Core Cooling System
EHC	electrohydraulic control
ELS	emergency load sequencer
ENS	Emergency Notification System
EOC	end of cycle
EOF	emergency offsite facility
EOL	end of life
EPA	electrical penetration assembly
ER	environmental report
ERF	emergency response facility
ERFDS	Emergency Response Facility Display System
ESF	engineered safety features
FATT	fracture appearance transition temperature
FCS	Feedwater Control System
FCD	flow control diagram
FFWT	final feedwater temperature
FHA	fuel handling accident
FMEA	failure modes and effects analysis
FPCC	fuel pool cooling and cleanup
FPS	Fire Protection System
FRVS	Filtration, Recirculation, and Ventilation System
FSAR	Final Safety Analysis Report
FSTF	full scale test facility
FWPCA	Federal Water Pollution Control Act
FWS	Feedwater System
GDC	General Design Criterion
GE	General Electric Company
GRA	Growth Rate Algorithm
GWMS	Gaseous Waste Management System

HCGS	Hope Creek Generating Station
HCU	hydraulic control unit
HEPA	High efficiency particulate air
HOAS	Hydrogen-Oxygen Analyzer System
HPCI	high pressure coolant injection
HPLPSI	high pressure/low pressure system interlocks
HVAC	heating, ventilating, and air conditioning
I&C	instrumentation and control
I/O	input/output
ICS	Integrated Control System
IED	instrument engineering diagram, or instrument electrical diagram, or instrument and electrical diagram
IES	Illumination Engineering Society
ILRT	integrated leak rate test
IRM	intermediate range monitor
LDBA	leakage design basis accident
LDIS	Leakage Detection and Isolation System
LDS	Leak Detection System
LEFM	linear elastic fracture mechanics
LER	licensee event report
LHGR	linear heat generation rate
LOCA	loss-of-coolant accident
LPCI	low pressure coolant injection
LPRM	local power range monitor
LPSP	low power setpoint
LPZ	low population zone
LSTG	Large Steam Turbine-Generator, General Electric Company
LTD	long time delay
LWMS	Liquid Waste Management System
LWR	light water reactor

M&TE	measuring and test equipment
MAPHGR	maximum average plant & heat generation rate
MCC	motor control center
MCHFR	minimum critical heat flux ratio
MCPR	minimum critical power ratio
MCR	main control room
MCRHIS	Main Control Room Habitability and Isolation System
MGV	motor generator ventilation
MPL	Master Parts List
MPC	maximum permissible concentration
MSIV	main steam isolation valve
MSIVSS	Main Steam Isolation Valve Sealing System (Deleted System)
MSSV	main steam stop valve
MSV	main stop valve
MTBE	mean time between events
NBS	National Bureau of Standards
NBU	Nuclear Business Unit
NCO	nuclear control operator
NDL	nuclear data link
NDT	nondestructive testing
NDTT	nil-ductility transition temperature
NEC	National Electric Code
NMS	Neutron Monitoring System
NPSH	net positive suction head
NRB	nuclear review board
NSOA	nuclear safety operational analysis
NSSS	Nuclear Steam Supply System
NSSSS	Nuclear Steam Supply System shutoff
NWS	National Weather Service
OBE	operating basis earthquake
OHLHS	Overhead Heavy Load Handling Systems
ORW	oily radwaste
OS	Operations Superintendent
OS&Y	outside screw and yoke (valve)

P&ID	piping and instrumentation diagram
PAMI	post-accident monitoring instrumentation
PASS	Post-Accident Sampling System
PBDA	Period Based Detection Algorithm
PCA	primary coolant activity
PCRVICS	Primary Containment and Reactor Vessel Isolation Control System
PCS	Process Computer System
PCIGS	Primary Containment Instrument Gas System
PCIS	Primary Containment Isolation System
PDM	Pittsburgh-Des Moines Steel Company
PLC	programmable logic controller
PMF	probable maximum flood
PMH	probable maximum hurricane
PORC	preoperational test review committee
PRMS	Process Radiation and Monitoring System
PRTGS	Pressure Regulator and Turbine-Generator System
PSS	Process Sampling System
PSAR	Preliminary Safety Analysis Report
PVC	polyvinyl chloride
PWR	pressurized water reactor
QA	quality assurance
QAD	quality assurance department
QAI	quality assurance instruction
QAM	quality assurance manual
QAP	quality assurance program
QSTF	quarter scale test facility
RACS	Reactor Auxiliaries Cooling System
RAMPS	Repair and Maintenance Procedure System
RBEAC	reactor building equipment area cooling
RBM	rod block monitor
RBSCR	reactor building to suppression chamber relief
RBVIS	Reactor Building Ventilation Isolation System
RBVS	Reactor Building Ventilation System

RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	Reactor Coolant System
RDCS	RMCS Rod Drive Control System
RFCS	Recirculation Flow Control System
RFPT	reactor feedpump turbine
RHR	residual heat removal
RHR-RSCM	residual heat removal-reactor shutdown cooling mode
RI	refueling interlocks
RMCS	Reactor Manual Control System
RMS	Radiation Monitoring System
RO	reactor operator
RPC	rod pattern controller
RPIS	Rod Position Information System
RPM	radiation protection manager
RPS	Reactor Protection System
RPT	recirculation pump trip
RPV	reactor pressure vessel
RRCS	Redundant Reactor Control System
RSCS	Rod Sequence Control System
RSF	remote shutdown facility
RSP	remote shutdown panel
RTD	resistance temperature detector
RWCU	reactor water cleanup
RWE	rod withdrawal error
RWM	rod worth minimizer
RWS	radwaste area supply
RWTF	radwaste area tank filter
SACF	single active component failure
SACS	Safety Auxiliaries Cooling System
SAF	single active failure
SAS	service area supply
SCDPR	suppression chamber to drywell pressure relief

SDIV	scram discharge instrument volume
SDV	scram discharge volume
SJAE	steam jet air ejector
SLC	standby liquid control
SOE	single operator error
SORC	station operations review committee
SPCM	suppression pool cooling mode
SPDS	Safety Parameter Display System
SPE	steam packing exhauster
SQAE	station quality assurance engineer
SQRT	seismic qualification review team
SRC	switchgear room unit coolers
SRLR	Supplemental Reload Licensing Report
SRG	safety review group
SRM	source range monitor
SRO	senior reactor operator
SRP	Standard Review Plan
SRV	main steam safety/relief valve
SRWE	solid radwaste exhaust
SRWS	solid radwaste supply
SS	nuclear shift supervisor
SSE	safe shutdown earthquake
SSNSSI	safety system/non-safety system isolation
SSVS	Safe Shutdown Equipment Ventilation System
SSWS	Station Service Water System
STA	shift technical advisor
STACS	Safety and Turbine Auxiliaries Cooling System
STCS	Steam Tunnel Cooling System
STD	short time delay
STMS	Startup Transient Monitoring System
SWIS	service water intake structure
SWMS	Solid Waste Management System
TBVS	Turbine Building Ventilation System
TCTFE	trichlorotrifluoroethane

TDH	total dynamic head
TDS	total dissolved solids
TID	total integrated radiation dose
TIP	traversing in-core probe
TLV	threshold limit valve
TSC	technical support center
TSCEF	technical support center emergency filters
TSCS	technical support center supply
TWS	traveling water screens
UBC	uniform building code
UCL	upper confidence limit
UPS	uninterruptible power supply
URC	ultrasonic resin cleaner
USPHS	United States Public Health Service
VBWR	Vallecitos Boiling Water Reactor
VFMG	variable frequency motor-generator
VRVS	Vacuum Relief Valve System
VWO	valves wide open
WAE	wing area exhaust
WAS	wing area supply
ZPA	zero period acceleration

TABLE 1.13-2

PIPING AND VALVE CLASS IDENTIFICATION

Pipe and valve classes are designated by a three-letter code. The first letter indicates the primary valve and flange pressure rating; the second letter, the type of material; and the third letter, the code to which the piping is designed.

First Letter - Primary Pressure Rating

A - Specific pressure at specific temperature
B - 2500 psi
C - 1500 psi
D - 900 psi
E - 600 psi
F - 400 psi
G - 300 psi
H - 150 psi
J - 125 psi ANSI B16.1
K - 175 psi WOG Underwriter's Laboratories, Inc
L - 250 psi ANSI B16.1
M - 200 psi WOG
N - 150 psi ANSI B16.24
P - 100 psi AWWA (or manufacturer's rating)
R - 75 psi AWWA (or manufacturer's rating)
S - 180 psi AWWA-non-Seismic Category I
T - 25 psi AWWA
V - Vendor supplied
X - Gravity rating
Y - 180 psi AWWA - Seismic Category I

Second Letter - Material

A - Alloy steel (1-1/4 Cr - 1/2 Mo)

B - Carbon steel

C - Austenitic stainless steel

D - Copper, brass or bronze

E - Aluminum bronze

F - Carbon steel - copper bearing

G - Carbon steel - cement mortar lined

H - Cast iron

I - 90 - 10 copper nickel

J - Alloy steel - 4-6 percent Cr

K - Fiberglass reinforced pipe

L - Carbon steel - impact tested

M - Cast iron - high silicon

N - Carbon steel - galvanized

P - Cast iron - cement mortar lined

Q - Ductile iron - teflon (FEP) lined

R - Ductile iron

S - Ductile iron - cement lined

T - Prestressed concrete

U - Carbon steel - saran lined

V - Carbon steel - polypropylene lined

W - Carpenter 20 CB-3 alloy

X - Carbon steel - epoxy phenolic lined

Y - Carbon steel - teflon (FEP) lined

Z - Reinforced concrete

Third Letter - Applicable Codes

A - Nuclear power plant components, ASME B&PV Code, Section III, Class 1

B - Nuclear power plant components, ASME B&PV Code, Section III, Class 2

C - Nuclear power plant components, ASME B&PV Code, Section III, Class 3

D - Power piping code, ANSI B31.1

E - Petroleum refinery piping code, ANSI B31.3

F - National Fire Protection Association code

G - The National Standard Plumbing code

H - Power boilers, ASME B&PV Code, Section I

I - Manufacturers standard

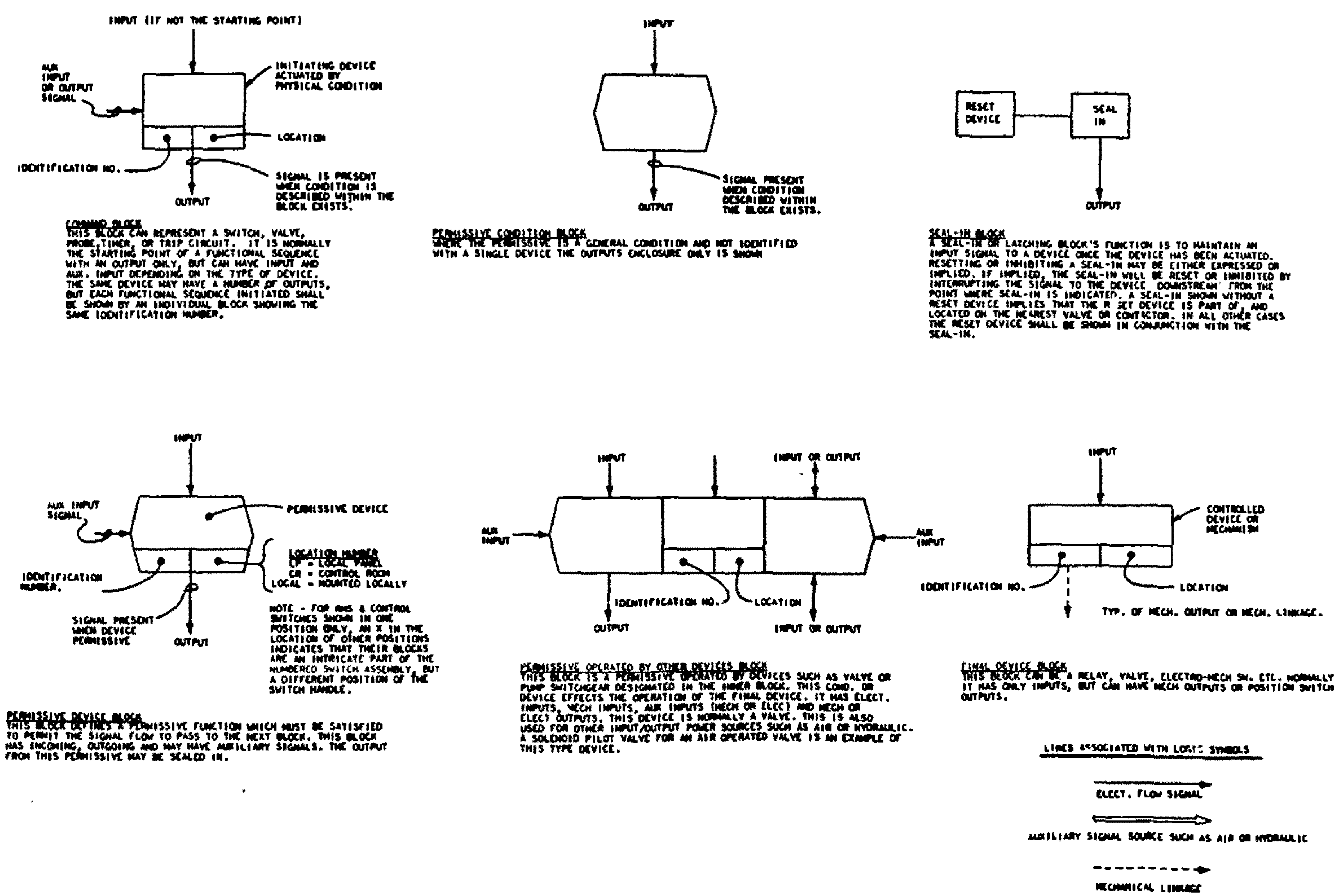
J - American Water Works Association

T - GE LSTG code

X - ASTM standards

Figure F1.13-1 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-00-0 for both sheets in DCRMS



REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

LOGIC SYMBOLS

UPDATED FSAR

FIGURE 1.13-2

1.14 GENERIC LICENSING ISSUES

1.14.1 Licensing Issues

HCGS has identified generic licensing issues from the dockets of several operating license applicants. These generic issues were originally in the form of NRC questions, and dealt with TMI related issues or Regulatory Guides which have undergone recent revision. HCGS has evaluated each of these issues and has a response to each of them in the following sections.

A list of these licensing issues is provided below:

Licensing Issue	Title
1	Internally Generated Missiles
2	CRD Return Line Removal
3	SRV Surveillance Program
4	SRV Performance Testing
5	Applicability of Liquid Flow Through SRV Test Performed in Response to TMI Action Plan Item II.D.1
6	Trip of Recirculation Pumps to Mitigate ATWS
7	Detection of Intersystem Leakage
8	RCIC Pump Suction Switchover
9	Unintentional Shutdown of the RCIC System
10	Design Adequacy of the RCIC System - Providing Automatic Restart Capability

11	Adequate SRV Fluid Flow
12	Provisions to Preclude Vortex Formation
13	Categorization of Valves Which Isolate RHR From Reactor Coolant System
14	Available Net Positive Suction Head
15	Assurance of Filled ECCS Line
16	Operability of ADS
17	Assurance For Long Term Operability of the Automatic Depressurization System (ADS)
18	Leakage Testing of Reactor Coolant System Isolation Valves
19	Assurance For Long-Term Operability of the Automatic Depressurization System
20	Control of Post-LOCA Leakage to Protect ECCS and Preserve Suppression Pool Level
21	Required Operator Action Assumed in LOCA Analysis in the 10 to 20 Minute Time Frame
22	Replace High Drywell Pressure Interlock on HPCS Trip Circuitry With Level-8 Trip to Prevent Main Steam Line Flooding
23	Additional LOCA Break Spectrum
24	LOCA Analysis With Closure of the Recirculation Flow Control Valve Closure

25	Adequate Time Available for Required Operator Action
26	Requirement for Automatic Restart of HPCS After Manual Termination
27	Adequate Core Cooling Maintained With LPCI Diversion
28	Temperature Drop With Feedwater Heater
29	Use of Nonreliable Equipment in Anticipated Operational Transients
30	Reliance on Nonsafety Grade Equipment in the Analysis of Recirculation Pump Shaft Seizure
31	ATWS
32	ODYN Transient Analysis Code
33	Classification of Load Rejection Without Bypass and Turbine Trip Without Bypass and Recalculation of MCPR
34	Proper Classification of Transients
35	Adequacy of the GEXL Correlation - Reload Operation
36	Core Thermal Hydraulic Stability Evaluation
37	Low or Degraded Grid Voltage
38	Test Results for Diesel Generators
39	Containment Electrical Penetrations
40	Adequacy of the 120 V ac RPS Power Supply
41	Thermal Overload Protection Bypass

42	Reliability of Diesel Generator
43	Diesel Generator Reliability
44	Shared DG Conformance to Regulatory Guide 1.81
45	Periodic Diesel Generator Testing
46	Special Low Power Testing Program
47	Emergency Procedures Reactivity Control Guidelines
48	Common Reference for Reactor Vessel Level Measurement
49	Reactor Coolant Sampling
50	Suppression Pool Sampling
51	Estimation of Fuel Damage from Post-Accident Samples
52	Failures in Vessel Level Sensing Lines Common to Control and Protective Systems
53	Physical Separation and Electrical Isolation
54	Redundancy and Diversity of High/Low Pressure System Interlocks
55	ATWS
56	Test Techniques
57	Potential for Both Low-Low Setpoint Valves to Open Due to a Single Failure
58	Safety System Setpoints, Instrument Range

59	IE Bulletin 80-06: Engineered Safety Feature Reset Control
60	Drawings
61	Control Systems Failure
62	RCIC Classification
63	Safety-Related Display
64	Rod Block Monitor
65	MSIV Leakage Control System **(Historical Information)**
66	Procedures Following Bus Failure (IE Bulletin 78-27)
67	Harsh Environment for Electrical Equipment Following High Energy Line Breaks
68	Steam Bypass of the Suppression Pool
69	Pool Dynamic LOCA and SRV Loads
70	Containment Dynamic Loads
71	Containment Purge System
72	Combustible Gas Control
73	Hydrogen Control Capability
74	Containment Leakage Testing
75	BWR Scram Discharge Volume Modifications
76	Safe Shutdown for Fires and Remote Shutdown System

77	Protection of Equipment in Main Steam Pipe Tunnel
78	Design Adequacy of the RCIC System Pump Room Cooling System
79	Reassessment of Accident Assumptions as Related to Main Steam Line Isolation Valve Leakage Rate
80	Asymmetrical LOCA, SSE and Annulus Pressurization Loads on Reactor Vessel, Internals, and Supports
81	Preoperational Vibration Assurance Program
82	RPV Internals Vibration Test Program for BWR/6
83	Dynamic Response Combination Using SRSS Technique
84	Input Criteria for Use of SRSS for Mechanical Equipment
85	Loading Combinations, Design Transients, and Stress Limits
86	Stress Corrosion Cracking of Stainless Steel
87	Pump and Valve Operability Assurance Program
88	Bolted Connections for Supports
89	Pump and Valve Inservice Testing Program
90	SRV In-Situ Test Program
91	CRD System Return Line Removal
92	Test Program Documentation for High and Moderate Energy Piping Systems

93 OBE Stress Cycles Used for the Mechanical Design on NSSS Equipment and Components

94 Kuosheng Incore Instrument Tube Break

95 Preservice and Inservice Inspection of Class 1, 2, and 3 Components

96 Inspectability of Welded Flued Head Design on Main Steam Line Containment Penetration

97 Clarification and Justification of the Methods Used to Construct the Operating Pressure/Temperature Limits

98 Exemptions from Appendix H to 10CFR50

99 Reactor Testing and Cooldown Limits

100 Exposure Resulting from Actuation of SRVs

101 Routine Exposures Inside Containment

102 Controlling Radioactivity During Steam Dryer and Steam Separator Refueling Transfer

103 Shielding of Spent Fuel Transfer Tube and Canal During Refueling

104 Combination of Loads

105 Fluid/Structure Interaction

106 Loads Assessment of Fuel Assembly Components

107 Combined Seismic and LOCA Loads Analysis on Fuel

108	Nonconservatism in the Models for Fuel Cladding, Swelling, and Rupture
109	Fuel Rod Cladding Ballooning and Rupture
110	High Burnup Fission Gas Release
111	Channel Box Deflection
112	Water Side Corrosion of Fuel Cladding Due to Copper in the Feedwater
113	Cladding Water Side Corrosion
114	Instruments to Detect Inadequate Core Cooling
115	Rod Withdrawal Transient Analysis
116	Fuel Analysis for Mislocated or Misoriented Bundles
117	Discrepancy in Void Coefficient Calculation
118	Bounding Rod Worth Analysis
119	Core Thermal Hydraulic Stability Analysis
120	Seismic Qualification of Equipment
121	Environmental Qualification of Equipment

1.14.1.1 Internally Generated Missiles, LRG I/RSB-1

1.14.1.1.1 Issue

Each applicant, on a plant specific basis, to demonstrate acceptability using one of, or a combination of, the following:

1. Provide protection from internally generated missiles

2. Perform analysis to show that missiles are not generated, or, if generated, have insufficient energy to cause unacceptable damage

This item relates to ACRS generic concern II-8, recirculation pump overspeed during a LOCA.

1.14.1.1.2 Response

The potential for internal missiles was discussed in Sections 3.5.1.1 and 3.5.1.2. It was concluded in these sections that internal missiles generated by rotating and pressurized components, and gravitationally generated missiles are not considered to be probable, or the consequences of a postulated missile have been evaluated, and safe shutdown of the plant is not affected.

1.14.1.2 CRD Return Line Removal, LRG I/RSB-2

1.14.1.2.1 Issue

The NRC staff was concerned with the impact of the elimination of the control rod drive (CRD) return line on the performance of the CRD system.

1.14.1.2.2 Response

The acceptability of the CRD system performance without the CRD return line (see Plant Drawing M-46-1) has been demonstrated by a GE analysis of the CRD performance characteristics.

1.14.1.3 SRV Surveillance Program, LRG II/3-RSB-3

1.14.1.3.1 Issue

LRG II participants must commit to participate in a safety/relief valve surveillance program.

1.14.1.3.2 Response

HCGS is participating in the BWROG program to test safety/relief valves. For further details see Section 1.10, Item II.D.1. Section 5.2.2.10 describes additional safety/relief valve inspection and test programs.

1.14.1.4 SRV Performance Testing/ LRG I/RSB-3

1.14.1.4.1 Issue

Additional information is required both for qualification tests and operating experience with the applicant's safety/relief valves.

1.14.1.4.2 Response

Section 5.2.2 describes the design, fabrication, test, installation and inspection requirements for the safety/relief valves. Section 1.10, Item II.D.1 describes the HCGS participation in the BWROG program to test safety/relief valves.

1.14.1.5 Applicability of the Liquid Flow Through SRV Tests Performed in Response to TMI Action Plan Item II.D.1, LRG II/6-RSB

1.14.1.5.1 Issue

An alternate shutdown cooling condition, which is considered in the design evaluation of many BWR plants, requires the flow of water through the safety/relief valve (SRV) and into the suppression pool.

In order to take credit for this alternate mode of shutdown cooling, it is necessary to demonstrate the ability of the SRVs and their discharge piping to withstand the resulting flow conditions.

1.14.1.5.2 Response

The original Hope Creek SRVs were Target Rock 2-Stage SRVs. The 2-Stage SRVs were qualified as described below.

The BWR Owners' Group SRV test program, undertaken to satisfy NUREG-0737 Item II.D.1 requirements, fully demonstrates the adequacy of the HCGS Target Rock SRVs for the alternate shutdown cooling mode of operation. The test program results are documented in General Electric Licensing Topical Report NEDE-24888-P/NEDO-24888. The Applicant's participation and the applicability of the test results to HCGS valves are described in Appendixes B and A, respectively, of that report.

Subsequently, Target Rock 3-Stage SRVs have been evaluated and approved for installation at Hope Creek. The Hope Creek 3-Stage SRVs utilize the same SRV Main body, require the same opening pressure in the electro-pneumatically operated mode (which is required for alternate mode of shutdown cooling) have the same response time, capacity and set pressures as the 2-Stage SRVs, and have been evaluated by the NSSS vendor General Electric (Report 001N2205, Hope Creek VTD 432432) to meet the requirements of NUREG 0737 Item II.D.1.

1.14.1.6 <u>Trip of Recirculation Pumps to Mitigate ATWS, LRG I/RSB-4</u>

1.14.1.6.1 Issue

The NRC staff required the overpressure protection analysis to consider the effect of an ATWS initiated recirculation pump trip (RPT).

1.14.1.6.2 Response

The overpressure protection analysis for the HCGS was done with credit taken for a RPT.

1.14.1.7 <u>Detection of Intersystem Leakage, LRG I/RSB-5</u>

1.14.1.7.1 Issue

Regulatory Guide 1.45 requires provisions to monitor systems connected to the RCPB for signs of intersystem leakage.

1.14.1.7.2 Response

HCGS interprets intersystem leakage as leakage from the reactor coolant pressure boundary (RCPB) and subsystems closely allied to the RCPB to secondary systems. Intersystem leakage is discussed in Sections 5.2.5.1.4, 11.5.2.2.16, and 11.5.2.2.17.

Leakage from the RCPB to the closely allied systems is not monitored directly because:

1. It does not represent a breach of the integrity of the RCPB

2. It does not threaten the ability to maintain water inventory

3. It does not jeopardize the integrity of the closely allied systems or the rest of the plant.

The principal reason for measuring RCPB leakage is to assure RCPB integrity. Leakage from the RCPB to closely allied systems does not indicate a degradation of the RCPB and leakage is expected to be well below the normal makeup capabilities of the feedwater and control rod drive systems.

Where it is possible that a low pressure system could become pressurized, due to leakage through a RCPB isolation valve, relief valves are provided to prevent overpressurization and to assure the integrity of the low pressure system. Periodic testing of the isolation valves between the RCPB and the closely allied systems will provide additional assurance that the integrity of the low pressure system will not be threatened.

1.14.1.8 RCIC Pump Suction Switchover, LRG I/RSB-6 and LRG II/6-RSB

1.14.1.8.1 Issue

The NRC staff wanted assurance of the availability of a Seismic Category I water source by an automatic switchover to the suppression pool upon failure of the condensate storage tank.

1.14.1.8.2 Response

The HCGS design incorporates an automatic transfer of the RCIC pump intake to the suppression pool when the water level in the condensate storage tank reaches a predetermined low level (see Section 1.10.2).

1.14.1.9 Unintentional Shutdown of the RCIC System, LRG I/RSB-7

1.14.1.9.1 Issue

Show how the design of the RCIC system prevents unintentional shutdown of the system, when the system is required, because of spurious ambient temperature signals from areas in and around the system (especially in the RCIC pump room).

1.14.1.9.2 Response

The temperature monitoring instrumentation provided for leak detection in the RCIC equipment compartment is described in FSAR Sections 5.2.5 and 7.6.1.3. The alarm and system isolation setpoints have been calculated based on analysis. The alarm/trip setpoints include sufficient margin to preclude spurious or unintentional annunciation or isolation. The temperature elements are located/or shielded so that they are sensitive to ambient air temperature and not radiated heat from operating equipment.

1.14.1.10 <u>Design Adequacy of the RCIC System - Providing Automatic Restart Capability, LRG II/2-RSB(a), LRG 11/2-RSB(b), LRG 11/2-RSB(d)</u>

1.14.1.10.1 Issue (LRG II/2-RSB(a))

TMI Action Plan Item 11.K.3.13 identified a need to modify the RCIC system to allow for automatic restart of the system at RPV Level 2 after the system has been tripped by a RPV Level 8 signal. The NRC Staff requires a commitment to install the automatic restart capability. The design details of this modification should also be provided.

1.14.1.10.2 Response (LRG II/2-RSB(a))

The HCGS response to TMI Action Plan Item 11.K.3.13 is provided in Section 1.10.2 of the HCGS FSAR.

1.14.1.10.3 Issue (LRG II/2-RSB(b))

TMI Action Plan Item II.K.3.15 identified a need to modify the break detection logic on the RCIC system steam supply line in order to prevent spurious isolation of the system. The NRC Staff requires a commitment to install a modification to correct the problem. The design details of this modification should also be provided.

1.14.1.10.4 Response (LRG II/2-RSB(b))

The HCGS response to TMI Action Plan Item II.K.3.15 is provided in Section 1.10.2 of the HCGS FSAR.

1.14.1.10.5 Issue (LRG II/2-RSB(d))

Provide water hammer protection for the RCIC system which is comparable to that provided for ECCS systems.

1.14.1.10.6 Response (LRG II/2-RSB(d))

As indicated by FSAR Section 5.4.6.2.4(f), water hammer protection is provided for the RCIC system which is comparable to that provided for the ECCS injection systems.

1.14.1.11 Adequate SRV Fluid Flow, LRG I/RSB-8

1.14.1.11.1 Issue

The applicant must perform tests to show that flow through the safety/relief valves is adequate to provide the necessary fluid relief required consistent with the analysis reported in Section 15.2.9 of the FSAR.

1.14.1.11.2 Response

See response to LRG Issue No. 5, Section 1.14.1.5.

1.14.1.12 Provisions to Preclude Vortex Formation, LRG II/7-RSB

1.14.1.12.1 Issue

To preclude vortex formation, air entrainment, and subsequent damage to ECCS pumps due to cavitation, it must be shown that adequate margin exists between the minimum suppression pool level and the depth of submergence of the ECCS pump suction strainers. This can be shown by analysis or by observations during pre-op testing that no vortex is formed.

1.14.1.12.2 Response

The ECCS pump suction strainers in the HCGS suppression chamber are provided with a minimum submergence of at least 10 feet, as measured from minimum suppression pool level. This amount of submergence has been analyzed to provide sufficient margin to preclude formation of vortices, as indicated by FSAR Section 6.3.2.2.5.

1.14.1.13 Categorization of Valve Which Isolates RHR from Reactor Coolant System, LRG I/RSB-8

1.14.1.13.1 Issue

We require that the valves which serve to isolate the Residual Heat Removal System from the Reactor Coolant System be classified category A/C in accordance with the provisions of Section XI of the ASME B&PV Code.

1.14.1.13.2 Response

Inservice testing of valves is discussed in Section 3.9.6.

1.14.1.14 Available Net Positive Suction Head, LRG I/RSB-10

1.14.1.14.1 Issue

The applicant must verify that the suction lines in the suppression pool leading to the ECCS pumps are designed to preclude adverse vortex formation and air injection which could affect the pumps' performance.

1.14.1.14.2 Response

See response to LRG Issue No. 12, Section 1.14.1.12.

1.14.1.15 Assurance of Filled ECCS Lines, LRG I/RSB-11

1.14.1.15.1 Issue

Instrumentation is not sufficiently sensitive to detect voids at the top of ECCS pipelines. The applicant must provide adequate instrumentation to assure filled ECCS lines.

1.14.1.15.2 Response

The design of the ECCS discharge line fill network is described in FSAR Section 6.3.2.2.6. The jockey pumps for the fill network will pressurize the ECCS pump discharge lines sufficiently above atmospheric pressure to preclude either air inleakage or the formation of voids at the top of ECCS pipelines. Instrumentation is provided for each of the ECCS pump discharge lines to detect unacceptably low pressure in the lines. To further ensure that the ECCS lines are full, the fill network is periodically surveillance tested in accordance with plant technical specifications.

1.14.1.16 <u>Operability of ADS, LRG I/RSB-12</u>

1.14.1.16.1 Issue

The applicant must show that the air supply for the ADS is sufficient for the extended operating time required and assures us the reliability data that the ADS valves will function as required.

1.14.1.16.2 Response

See response to LRG Issue No. 17, Section 1.14.1.17.

1.14.1.17 <u>Assurance for Long Term Operability of the Automatic Depressurization System (ADS), LRG II/8-RSB</u>

1.14.1.17.1 Issue

TMI Action Plan Item II.K.3.28 identified the need to assure that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressures. The long term air supply must also be designed to withstand a hostile environment and still perform its function 100 days after an accident.

Since the time when the ADS would be needed during or after an accident is dependent upon a variety of scenario specific unknowns such as equipment availability, operator actions, break size, etc., it is unacceptable to NRC to allow the ADS to be unavailable anytime the reactor is pressurized.

Leakage through the accumulator check valves must not disable the ADS before action is taken to provide the backup air supply. No single active failure may disable the long term air supply.

1.14.1.17.2 Response

The response for TMI Action Plan Item II.K.3.28 is discussed in Section 1.10.

1.14.1.18 Leakage Testing of Reactor Coolant System Isolation Valves, LRG I/RSB-13

1.14.1.18.1 Issue

Periodic testing and establishment of leak rate criteria required for the valves that isolate the Reactor Coolant System from all the emergency core cooling systems.

1.14.1.18.2 Response

Leakage testing of isolation valves and acceptance criteria for the tests are discussed in Sections 6.2.4 and 6.2.6, and Table 6.2-16.

1.14.1.19 Assurance for Long Term Operability of Deep Draft Pumps, LRG II/9-RSB and LRG I/RSB-14

1.14.1.19.1 Issue

IE Bulletin 79-15, dated July 1979, identified problems with deep draft ECCS pumps that could threaten their long term post-LOCA operability. Structure flexibility, shaft/column misalignment, vibrational frequencies near rotation speeds, inlet flow induced vortices, and dimensional deficiencies such as those discovered with certain LaSalle ECCS pumps, could cause excessive vibration and bearing wear. The NRC staff has asked applicants to define programs and provide data that compare the expected service life with the accumulated operating time and confirm the long term operability.

1.14.1.19.2 Response

The inherent design features of the Ingersoll Rand ECCS pumps in HCGS preclude excessive vibration and bearing wear. Each pump is supplied with a casing or suction barrel and is not installed in a wet sump. They do not have long, limber columns; the longest pump is only 18 feet, compared to the 30 to 60-foot pumps described in IE Bulletin 79-15. Also the pump assembly rigidity is enhanced by a seismic pin. The pumps use a double suction first stage to provide stability over a wide range of flows. Column frequencies are well removed from pump speed. Larger diameter barrels provide low flow velocities around pump inlets, and pin seismic restraints act as flow straighteners to suppress vortex formation. The pumps have high precision, keyed, sleeve type couplings.

Long term operability is assured by the use of a predictive maintenance program, and periodic functional testing under the In Service Testing (IST) Program. The predictive maintenance program tracks and trends the vibration and performance data collected under the IST Program. When the data indicates a reduction in pump performance, pump repairs or overhaul are performed to restore the pump's performance. Functional testing measurements of pump inlet pressure, differential pressure, flow rate, and vibration, quarterly as prescribed by OM – Part 6 of the ASME B&PV Code, provide data for engineering analysis to identify performance changes or trends. In addition, vibration data bases are maintained and compared with functional testing vibration data to monitor journal bearing wear and shaft whip.

1.14.1.20 Control of Post-LOCA Leakage to Protect ECCS and Preserve Suppression Pool Level, LRG II/5-RSB

1.14.1.20.1 Issue

The applicant must demonstrate that passive failures (i.e., leakage from the first isolation valve outside of the suppression pool) will be contained so that the suppression pool is not drained nor is redundant ECCS equipment flooded.

1.14.1.20.2 Response

The ECCS suction lines and the isolation valves between the suppression chamber and the ECCS pumps are safety grade. The isolation valves are designed to preclude leakage, and no seals or gaskets are installed between the containment penetration and the isolation valves.

Leak detection and mitigation capabilities for the ECCS pump compartments are discussed in FSAR Sections 5.2.5 and 9.3.3.5.

1.14.1.21 Operator Action Required/Assumed in LOCA Analyses in the 10-to-20 Minute Time Frame, LRG II/4-RSB

1.14.1.21.1 Issue

Section 6.3 of the Standard Review Plan states that no credit for operator actions should be taken in loss-of-coolant accident (LOCA) analyses prior to 20 minutes into the transient.

1.14.1.21.2 Response

The LOCA analyses for the HCGS meet the SRP criterion. No operator actions are required within 20 minutes. While 10-minute operator actions are assumed in the containment analyses, the actions are assumed for the purpose of adding conservatism to the analyses rather than to meet a design requirement. Further description is provided in Sections 6.2 and 6.3.

1.14.1.22 Replace High Drywell Pressure Interlock on HPCS Trip Circuitry with Level-8 Trip to Prevent Main Steam Line Flooding, LRG II/13-RSB

1.14.1.22.1 Issue

Other designs included an interlock that prevented shutoff of the flow of the high pressure core spray at high water level (8) in the reactor vessel when a high drywell pressure signal is present. Such systems should be removed.

1.14.1.22.2 Response

HCGS has no high pressure core spray.

1.14.1.23 Additional LOCA Break Spectrum, LRG I/RSB-15

1.14.1.23.1 Issue

The NRC staff requested the following additional LOCA analyses to complete the break spectrum:

1. An additional recirculation line break with a discharge coefficient 0.6 times the design bases accident, using the large break model analysis.

2. An additional recirculation line break with a 0.02 ft^2 area, using the small break model analysis.

1.14.1.23.2 Response

The adequacy of the LOCA break spectrum is addressed in Section 6.3.3. The lead plant analyses (Brunswick), supported by confirmatory plant unique Appendix K calculations, have been found acceptable to the NRC staff without further commitment.

1.14.1.24 LOCA Analyses with Closure of the Recirculation Flow Control Valve, LRG I/RSB-16 and LRG II/10-RSB

1.14.1.24.1 Issue

The ECCS analyses described in Section 6.3 assume the nonsafety grade, recirculation flow control valve (FCV) locks at its existing position during the LOCA. The NRC staff requested a discussion of the effects on the analyses if it is assumed the FCV closes at a realistic rate and of the probability the FCV will fail in this manner.

1.14.1.24.2 Response

The HCGS recirculation system does not contain a FCV so this issue is not applicable to the HCGS.

1.14.1.25 Adequate Time Available for Operator Action Required, LRG I/RSB-17

1.14.1.25.1 Issue

In an applicant's analysis to evaluate a crack in the residual heat removal line postulated to occur during normal shutdown cooling, operator action was indicated to restore core cooling. The NRC staff required the applicant to show that adequate time is available for this operator action.

1.14.1.25.2 Response

Should the RHR shutdown cooling line crack during a normal shutdown, a total reactor isolation will automatically occur. Subsequently, vessel water will decrease to Level 2, and automatic initiation of

HPCI will occur. HPCI will cycle on and off between Levels 2 and 8 until the operator establishes an alternate water source.

If HPCI were unavailable, representative analyses for similar BWR/4 plants have been performed to demonstrate that operator action would not be required before 20 to 30 minutes following the pipe crack to assure adequate core cooling in accordance with the acceptance criteria of 10CFR50.46.

1.14.1.26 Requirement for Automatic Restart of HPCS After Manual Termination, LRG II/1-RSB

1.14.1.26.1 Issue

The NRC staff required a commitment to install the automatic restart of high pressure core spray (HPCS) on low reactor vessel water level after manual termination by the operator.

1.14.1.26.2 Response

This issue is not applicable to the HCGS because it does not have a HPCS.

1.14.1.27 Adequate Core Cooling Maintained with LPCI Diversion, LRG I/RSB-18

1.14.1.27.1 Issue

The NRC staff asked for a demonstration that adequate core cooling would be maintained if the flow of the low pressure coolant injection were diverted to the wetwell and drywell sprays and to suppression pool cooling.

1.14.1.27.2 Response

This situation is addressed in Section 6.3. Sufficient margin exists in the peak cladding temperature to accommodate the diversion of low pressure coolant injection at 600 seconds into the transient. This demonstrates adequate core cooling.

1.14.1.28 Temperature Drop with Feedwater Heater Failure, LRG I/RSB-19

1.14.1.28.1 Issue

The analysis of the feedwater heater failure event is based on a temperature drop no greater than 100°F. However, an actual failure demonstrated a 150°F drop. The NRC staff has requested a justification for the smaller temperature drop or a reanalysis with a justified temperature decrease.

1.14.1.28.2 Response

The design specification for the Feedwater Heating System requires that the maximum temperature decrease due to a single failure be no greater than 100°F. Sufficient analyses have been performed for BWR/4 plants to show that the net effect of a larger temperature drop is an earlier scram initiation rather than a change in the critical power ratio (CPR). The resulting minimum CPR is essentially unchanged, and this event is not the limiting event for establishing the operating limit on the minimum CPR.

1.14.1.29 Use of Nonreliable Equipment in Anticipated Operational Transients, LRG I/RSB-20

1.14.1.29.1 Issue

In analyzing anticipated transients, if credit is taken for equipment that has not been shown to be reliable, this equipment should be identified in the technical specifications with regard to availability, setpoints, and surveillance testing.

1.14.1.29.2 Response

The NRC staff's concern for the use of nonsafety grade equipment in the analysis of transient mitigation is exemplified by questions on many dockets relative to credit taken for:

1. Non-Class 1E relief function versus setpoints for Class-1E safety functions

2. Inputs to the Reactor Protection System from the turbine building

3. The level-8 turbine trip and the Turbine Bypass System.

A November 1978 GE/NRC meeting determined that the most limiting anticipated operation transient with an analysis that takes credit for nonsafety-grade equipment is the excess feedwater transient analysis that relies on a level-8 turbine trip and turbine bypass. The NRC staff agreed that technical specifications for the level-8 turbine trip and the turbine bypass valves would satisfactorily resolve this issue. The HCGS technical specifications will include appropriate provisions regarding the availability, setpoints, and surveillance testing of the trip system and bypass valves.

1.14.1.30 <u>Reliance on Nonsafety-Grade Equipment in the Analysis of Recirculation-Pump Shaft Seizure, LRG /RSB-21 and LRG II/11-RSB</u>

1.14.1.30.1 Issue

Demonstrate that the limit for the minimum critical power ratio of 1.06 and the 10CFR 00 limits are not violated when the analysis of this accident does not take credit for nonsafety grade equipment.

1.14.1.30.2 Response

The nonsafety-grade equipment for which credit is taken in this analysis (Section 15.3.3) are the level-8 turbine trip and the Turbine Bypass System. Failure of the level-8 turbine trip would produce a transient no worse than if a level-8 trip had occurred, and it would be less severe than the recirculation pump trip event (Section 15.3.1) because the eventual turbine trip (due to high steam moisture and/or turbine vibration) would be at a reduced fuel heat flux. Failure of the turbine bypass would produce a transient similar to but less severe than a turbine trip without bypass (Section 15.2.3) and also would be bounded by the feedwater controller failure event without bypass because of the reduced core power at the time of the turbine trip.

1.14.1.31 ATWS, LRG I/RSB-22

1.14.1.31.1 Issue

The issue requires the applicant to:

1. Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.

2. Train operators to take actions in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, tripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the Standby Liquid Control (SLC) System, and prompt placement

of the RHR in the suppression pool cooling mode to reduce the severity of the containment conditions.

1.14.1.31.2 Response

The following actions will be implemented at HCGS in order to further reduce the risk associated with ATWS events:

HCGS is implementing Alternate 3A of NUREG-0460, with manual initiation of the SLC system. Emergency procedures will be developed for ATWS events. These procedures will address the following:

1. Symptoms

2. Automatic actions

3. Immediate actions

4. Subsequent actions

5. Final conditions

Operators will be trained to perform the proper actions for ATWS events as part of the formal operator training program.

Emergency operating procedures have been developed from the BWR Owners' Group Emergency Procedure Guidelines (EPGs). Although these procedures are symptomatic in nature, specific actions are provided to mitigate ATWS events.

The development of these procedures is described in the PGP and P-STG which have been submitted for NRC review.

Subsequent revisions to the emergency operating procedures will be developed from revisions to the BWR Owner's Group EPGs, as applicable. Description of the process used to revise the EOPs is contained in the applicable administrative procedures.

1.14.1.32 ODYN Transient Analysis Code, LRG I/RSB-23

1.14.1.32.1 Issue

The NRC staff requested that the pressurization transients be reevaluated and assessed using the ODYN computer code. At the time the NRC had not completed its review of the ODYN code.

1.14.1.32.2 Response

The ODYN code has been reviewed and accepted by the NRC. All the pressurization transients in Sections 5 and 15 were analyzed using the ODYN code.

1.14.1.33 Classification of Load Rejection Without Bypass and Turbine Trip Without Bypass and Recalculation of MCPR, LRG I/RSB-24 and LRG II/12-RSB

1.14.1.33.1 Issue

The minimum critical power ratio (MCPR) should be recalculated for the generator load rejection event, taking into consideration that turbine bypass fails. The NRC staff disagrees with an infrequent occurrence classification for this event, hence the operating limit should be modified to satisfy the MCPR limit of 1.06.

1.14.1.33.2 Response

This issue is addressed in Sections 15.2 and 15.3. In spite of an infrequent occurrence classification, the ODYN code was used to analyze load rejection without bypass and turbine trip without bypass. Neither transient is limiting in determining the operating limit for the MCPR.

1.14.1.34 Proper Classification of Transients, LRG II/12-RSB

1.14.1.34.1 Issue

The minimum critical power ratio (MCPR) should be recalculated for the generator load rejection event, taking into consideration that turbine bypass fails. The NRC staff disagrees with an infrequent occurrence classification for this event, hence, the operating limit should be modified to satisfy the MCPR limit of 1.06.

1.14.1.34.2 Response

See response to LRG Issue No. 33, Section 1.14.1.33.

1.14.1.35 Adequacy of the GEXL Correlation, LRG I/RSB-25

1.14.1.35.1 Issue

The GEXL correlation must de demonstrated to be applicable to the 8X8 design by comparison to applicable data.

1.14.1.35.2 Response

The NRC staff has concluded that the GEXL correlation is conservative for the first core cycle. Adequate negative worth is provided by the control rods to assure shutdown capability.

1.14.1.36 Core Thermal Hydraulic Stability Analyses, LRG I/RSB-26 and LRG II/11-CPB

1.14.1.36.1 Issue

Fuel design changes have increased the maximum decay ratio (MDR) beyond the original design criterion of 0.5 for thermal hydraulic stability, and the NRC staff has not accepted General Electric's proposed new criterion of 1.0. The Staff has approved for operation previous core designs with MDRs as high as 0.7 for the initial cycle, but it will condition the licenses of BWR/6s (MDR = 0.98) to prohibit operation at natural circulation and to require new stability analyses be submitted and approved prior to second cycle operation. The NRC is performing a generic study of the hydrodynamic stability characteristics of light water reactors. The results will be applied to the Staff's review and acceptance of stability analyses, criteria, and analytical methods of reactor vendors.

1.14.1.36.2 Response

Sufficient documentation of an adequate stability margin for the HCGS first cycle has been provided. As a result of the NRC staff position in references 1 and 2, future cycle specific stability margin analysis is not required. In addition, Technical Specification 3/4.4.1 states the operating limitations which provide for the detection and suppression of flux oscillations in operating regions of potential instability consistent with the recommendations of General Electric SIL-380. The NRC staff has found this acceptable to demonstrate compliance with GDC 10 and GDC 12 for cores loaded with approved fuel designs.

1.14.1.36.2.1 Response References

1. NRC Letter, C. O. Thomas to H.C. Pfefferlen, Acceptance for Referencing of Licensing Topical Report NEDE-24011, Rev. 6, Amendment 8, "Thermal Hydraulic Stability Amendment to GESTAR II", dated April 24, 1985.

2. NRC Letter, R. M. Bernero to All Licensees of Operating BWR's, "Technical Resolution of Generic Issue B-19-Thermal Hydraulic Stability (Generic Letter No. 86-02)", dated January 23, 1986.

1.14.1.37 <u>Low or Degraded Grid Voltage, LRG I/PSB-1</u>

1.14.1.37.1 Issue

Either:

1. Applicant will commit to implement a second level of undervoltage protection consistent with the guidance provided by the NRC Staff before the start of the second fuel cycle; or

2. Applicant will demonstrate the adequacy of the grid without the second level of voltage protection to the satisfaction of the NRC staff.

3. Provide system voltages at all levels during degraded grid voltage condition.

1.14.1.37.2 Response

Undervoltage relays for monitoring degraded grid voltage have been implemented into the HCGS design. System voltage studies have established the setpoints of these undervoltage relays. The setpoints for these relays and system voltages at various buses for various operating conditions are discussed in Section 8.3.1.2.1.

1.14.1.38 <u>Test Results for Diesel Generators, LRG I/PSB-2</u>

1.14.1.38.1 Issue

Test results for the diesel generators to indicate margin are to be provided.

1.14.1.38.2 Response

This issue is related to the diesel generator for HPCS system. This issue does not apply, since the high pressure coolant injection pump for HCGS plant is steam turbine driven.

1.14.1.39 Containment Electrical Penetrations, LRG I/PSB-3

1.14.1.39.1 Issue

The reactor containment electrical penetrations shall conform to Regulatory Guide 1.63 and test results shall demonstrate that the electrical penetrations can maintain their integrity for maximum fault current.

1.14.1.39.1.1 Position

The penetration design will conform to position C1 of Regulatory Guide 1.63 (Oct 1973) with respect to backup overcurrent protection; either:

1. "Incorporating adequate self-fusing characteristics within the penetration conductors themselves constitute an acceptable design approach"; or

2. "Where self-fusing characteristics are not incorporated the current overload protection system will conform to the single failure criteria of IEEE-279(1971) Section 4.2; ANSI-N42.7(1972)".

Note

1. Position 2 above applies to power circuits only. Control and instrument circuits are not subject to detrimental high level fault currents.

2. Regulatory Guide 1.63, Rev. 1 (May 1977) was identified for implementation on CP applications docketed after December 30, 1977. In addition, as listed in NUREG-0427 Table III-13 and III-14; Regulatory Guide 1.63 is identified as a Category I or Category II item. As such applicants shall be allowed to demonstrate the adequacy of Rev. 0 of the Regulatory Guide.

3. The positions discussed above are not applicable to Fermi-2. The issue is considered closed by NUREG-0314.

1.14.1.39.2 Response

The design of the HCGS electrical penetration assemblies is in compliance with Regulatory Guide 1.63 as discussed in Section 8.1.4.12.

1.14.1.40 Adequacy of the 120 V ac RPS Power Supply, LRG I/PSB-4 PRS-4

1.14.1.40.1 Issue

The NRC staff questioned the adequacy of the 120 V ac power supply for the Reactor Protection System.

1.14.1.40.2 Response

This issue is addressed in Section 8.3.1.5. The MS set design modification developed by General Electric has been incorporated in the HCGS design.

1.14.1.41 Thermal Overload Protection Bypass, LRG I/PSB-5

1.14.1.41.1 Issue

NRC required the applicant to provide the detailed analysis and/or criteria used to select the setpoints for the thermal overload protective devices for valve motors in safety systems and the details as to how the devices will be tested.

1.14.1.41.2 Response

Position C.1.b of Regulatory Guide 1.106 has been implemented in the HCGS design. Under this position the thermal overload contact for a safety-related motor operated valve that is normally operational during plant operation is bypassed during accident conditions.

The requirements for main control room indication of bypasses alluded to by the reference to Section 4.13 of IEEE-279 is judged not to be applicable because no "protective action" is involved. This position was found acceptable by the NRC staff on the Zimmer docket (SER 7.1.3).

1.14.1.42 <u>Reliability of Diesel Generator, LRG I/PSB-6</u>

1.14.1.42.1 Issue

Reliability of Diesel Generator.

1.14.1.42.2 Response

Each standby diesel generator will be tested in accordance with HCGS Technical Specification 4.8.1.1.2.

1.14.1.43 <u>Diesel Generator Reliability, LRG II/1-PSB</u>

1.14.1.43.1 Issue

The NRC issued specific recommendations on increasing the reliability of nuclear power plant emergency diesel generators via the document NUREG/CR-0660, "Enhancement of Onsite Emergency Diesel Generator Reliability". Information requests concerning these recommendations are routinely transmitted to the applicants during the review process.

1.14.1.43.2 Response

HCGS intends to implement the appropriate recommendations of NUREG/CR-0660 as they apply to the onsite standby diesel generators.

A summary of each recommendation is given below by a discussion of how the recommendation will be implemented.

1.14.1.43.2.1 Recommendation 1 - Moisture in Air Starting System

The Air Starting System for the diesel generators relied on periodic blowdown of the air receivers for removal of entrained oil and excess water from the starting air. Operating experience has shown that accumulation of water in the Starting Air System has been one of the most frequent causes of diesel engine failure to start. It is recommended that air dryers be installed upstream of the air receivers.

1.14.1.43.2.1.1 HCGS Compliance

HCGS uses an air dryer upstream of the air receivers to ensure a continual supply of dry starting air. The receivers also have drain valves.

1.14.1.43.2.2 Recommendation 2 - Air Quality in Diesel Generator Room

Malfunction or failure of the contacts and relays to function properly is another major cause of diesel engine failure to start. The root cause is usually dust, dirt and grit between the electrical contact surfaces. It is recommended that all contacts and relays be inside dust tight enclosures and that dust control measures be implemented in the diesel generator rooms.

1.14.1.43.2.2.1 HCGS Compliance

In order to protect electrical contact surfaces, diesel generator control panels are dust tight and drip proof in accordance with the design requirements for NEMA type 12 cabinets.

In order to control dust in the area of the diesel generators, each unit is placed in its own cell. During normal plant operation, the ventilation systems provide filtered air, as a minimum, to areas containing diesel generator electrical controls. Ventilation system filters will be cleaned or replaced periodically.

1.14.1.43.2.3 Recommendation 3 - Turbocharger Heavy Duty Gear Drive

The scheduling and frequency of surveillance testing can result in excessively long periods of no load and light load running of a diesel generator at full rated speed.

This light loading results in insufficient exhaust gas energy to drive the turbocharge on the General Motors - Electro-Motive Division (GM-EMD) diesel engines. This results in the need to mechanically drive the turbocharger. Mechanically driving the turbocharger will result in a short life expectancy for the standard design turbocharger gear drive. It is recommended that a heavy duty gear drive be installed on the turbocharger.

1.14.1.43.2.3.1 HCGS Compliance

This issue is not applicable since the HCGS diesel engines are by Colt-Pielstick. These engines do not have turbocharger gear drives. The turbochargers are driven by the exhaust gases only and are designed to operate properly even when no load is applied.

1.14.1.43.2.4 Recommendation 4 - Personnel Training

There is a particularly difficult problem in developing knowledge and maintaining skills of the operators and maintenance personnel of the diesel generator units. These units normally operate only during surveillance and trouble shooting tests to give assurance of readiness, should an emergency arise. The relatively short exposure to an operating unit makes "on the job" training especially difficult. When a nuclear power plant is put into operation, the operators having the diesel generator responsibility may have little or no related skills on such units. It is recommended that the training of the operators and maintenance personnel, and especially their immediate supervisors, be an intensive and continuing education program. This would serve to develop knowledge and skills among those less experienced and act as "refresher training" to maintain the familiarity and skills of the qualified personnel.

1.14.1.43.2.4.1 HCGS Compliance

PSE&G will provide ongoing training for the maintenance personnel. Vendor training programs will be contracted for prior to operation.

1.14.1.43.2.5 Recommendation 5 - Automatic Pre-Lube

Long periods on standby have a tendency to drain or nearly drain the engine lube oil piping systems. On an emergency start of the engine as much as 5 to 14 or more seconds may elapse from the start of cranking until full lube oil pressure is attained even though full engine speed is generally reached in about five seconds. With an essentially dry engine, the momentary lack of lubrication at the various moving parts may damage bearing surfaces with resultant equipment unavailability.

It is recommended that the engine's electrically driven pre-lube pump be started by the same signal which initiates the cranking of the engine and be stopped when the engine stops cranking. An alternative approach would be to start the pre-lube pumps by the same signal but stop the pump when the pressure in the engine lube oil header has achieved a predetermined level. An electrically driven pre-lube pump accelerates to full speed quite rapidly with full delivery while the engine driven pump accelerates more slowly with the engine. In either case, such modifications should be carried out in close consultation with the engine manufacturer.

1.14.1.43.2.5.1 HCGS Compliance

The HCGS diesel engines are provided with a keepwarm/prelube system. This system is operated continuously, thus providing adequate lubrication to the various moving parts and bearing surfaces at all times.

1.14.1.43.2.6 Recommendation 6 - Testing Loading and Preventative Maintenance

Testing and test loading are the essence of the surveillance test as practiced in the nuclear power plant. The basic function and value of a surveillance test on a diesel generator unit is to demonstrate operability. The following recommendations are provided to guide and standardize the general approach in surveillance testing:

1. No load and light load operation causing incomplete combustion should be minimized to reduce the formation of gum and varnish deposits on engine parts and to reduce the likelihood of mechanical failures. Minimum load should be at least 25 percent of rated load.

2. The surveillance test should be within the NRC guidelines and the frequency of testing, size of test load, and duration should generally follow the recommendations of the engine manufacturer.

3. Investigative testing, replacement and adjustment should be part of the preventative maintenance program. Testing, per se, is not a corrective measure and serves only as confirmation of readiness and operability, or as an indication of the need for corrective action.

4. A "check off test" should be the final step after any corrective action. An actual start, run, and load test would help to determine if mistakes were made during a corrective action.

1.14.1.43.2.6.1 HCGS Compliance

The HCGS position on the above recommendation is as follows:

1. For no load and light load operation, the following conditions will be satisfied.

    (a) Implement the manufacturer's recommendations for no load and light-load operations.

    (b) During periodic testing, the diesel will be loaded to a minimum of 25 percent of full load or as recommended by the manufacturer.

    (c) During troubleshooting, no load operation will be minimized. If the troubleshooting operation is over an extended period (that is, 3 to 4 hr or more), the engine shall be cleared in accordance with item 1 above.

2. Surveillance testing of standby diesel generators will comply with requirements provided in the HCGS Technical Specifications. These Technical Specifications will reflect the NRC guidance provided in the BWR Standard Technical Specifications, NUREG-0123 Rev. 3.

3. Preventive maintenance will go beyond the normal routine adjustments, servicing, and repair or components when a malfunction occurs. The preventive maintenance program will encompass investigative testing of components that have a history of repeated malfunctioning and require constant attention of repair. Furthermore, industry operating experience from sources such as the nuclear plant reliability

data system will be utilized as an aid in evaluating industry history for diesel generator component failure.

4. Upon the completion of repairs or maintenance and before an actual start, run, and load test, a final equipment check will be made to ensure that all electrical circuits are functional; that is, fuses are in place, switches and circuit breakers are in their proper position, no wires are loose, all test leads have been removed, and all valves are in the proper position to permit a manual start of the equipment. After the unit has been satisfactorily started and load tested, it will be returned to automatic standby service.

1.14.1.43.2.7 Recommendation 7 - Identification of Root Causes of Failures

Improvement in reliability hinges on identification of the basic problem or "root cause" and the proper choice of corrective action. The effectiveness of all efforts to improve reliability depends on the proper execution in finding the true root cause of problems. This is especially difficult because of the usual chain of related cause and effect relationships.

In order to detect "root causes" of problems, the following guidance should be observed:

1. The obvious cause should always be suspect as the "root cause". To be sure, the obvious is usually the direct cause of failure or malfunction. The possible chain of cause and effect may fail to be investigated.

2. Closely spaced component failures should not be accepted unless accompanied by specific assurance of the absence of contributing causes and that alternate improved components are unavailable.

3. The LER system and the records so produced have proven to be the best single source of information on the reliability status of the emergency diesel generators. Continued reliance of this source of information for reliability data should be encouraged.

1.14.1.43.2.7.1 HCGS Compliance

In general, the above recommendations are inherent in the philosophy of good engineering and operating judgment. Such a philosophy is difficult to incorporate directly into a maintenance procedure and therefore is best accomplished as a function of an onsite review group. The purpose of such a group is to independently review atypical events, repetitive events and operating data from other stations in order to improve plant safety. PSE&G will establish such review groups in compliance with TMI Action Plan Item I.B.1.2 as contained in NUREG-0737.

1.14.1.43.2.8 Recommendation 8 - Diesel Generator Room Ventilation and Combustion Air Inlet

Some installed diesel generator units take their combustion air from the engine room regardless of the extent of airborne dirt and the arrangement of the Fire Suppression System. Some units have inherent recirculation of hot cooling system air, hot room ventilation air, and even hot exhaust gas. It is recommended that the following design guidance be observed for ventilation and combustion air inlet systems:

1. Engine combustion air should be through piping directly from outside the building and at least 20 feet from ground level through proper filters.

2. Room ventilation air should be filtered and taken from a level at least 20 feet above ground level. The piping for the room ventilation air should be separate from that used for the engine combustion air.

3. Room ventilation air, hot cooling system air and/or engine exhaust gas should not be permitted to circulate back into the diesel generator room, fuel storage area, or into any other part of the power plant.

1.14.1.43.2.8.1 HCGS Compliance

The HCGS position on the above recommendations are as follows:

1. A separate source of combustion air for each diesel engine is taken from the diesel outside air intakes which are located at least 20 feet above ground level. This air is filtered prior to combustion.

2. The Auxiliary Building Ventilation System air is drawn from intakes which are at least 20 feet above ground level. As a minimum, ventilation for areas which house control equipment with electrical contacts is filtered. The piping for the Auxiliary Building Ventilation System is separate from that used for the engine combustion air.

3. The air intake and exhaust gas openings are designed to prevent contamination of the intake air by exhaust products. Room ventilation air is recirculated to cool the diesel generator rooms when the diesels are running. It is a closed system not connected to the air intake or exhaust systems.

1.14.1.43.2.8 Recommendation 9 - Fuel Oil Storage and Transfer

In order to assure proper fuel oil storage and handling, the following recommendations are made:

1. Bulk fuel storage tanks should have provisions for water removal. In addition, the fuel outlet pipe should be several inches above the tank bottom to allow some tank volume for settling of any water.

2. Fuel supply pumps for the engine fuel system should be engine driven. The fuel supply to the engine driven fuel pump should either be an assured gravity fed supply or else by a booster pump powered from a Class 1E station battery.

1.14.1.43.2.8.1 HCGS Compliance

The HCGS position on the above recommendations is as follows:

1. Bulk fuel oil storage tanks have provisions for water removal. Water removal is via a drain located at the bottom of the tank.

   The suction point in each storage tank is located six inches from the tank bottom to prevent any accumulated water from being transferred to the day tank.

2. Fuel supply pumps for the engine fuel system are engine driven. The fuel supply to these pumps is an assured gravity fed supply from the day tank.

1.14.1.43.2.10 Recommendation 10 - High Temperature Insulation for Overload Conditions

The nature of the emergency diesel generator duty includes a possibility of large overloads which could extend longer than the time required to start large water pumps, etc. There is a possibility of engine overheating from such extreme emergency overloads causing a generator fire. It is recommended that high temperature rated generator insulation be utilized for the diesel generator units to reduce the generator fire hazard.

1.14.1.43.2.10.1 HCGS Compliance

Adequate reliability is provided by the design, margin, and qualification testing requirements that are applied to HCGS standby diesel generators.

1.14.1.43.2.11 Recommendation 11 - Engine Cooling Water Temperature Control

A water thermostat of the "3-way" or bypass type splits the water flow so that only as much water passes through the coolers or radiator as needed to maintain the proper water outlet temperature. This type of cooling water temperature control is used in most nuclear power plant diesel engine cooling systems and was the only design reviewed which gave no indication of trouble. It is recommended that all engine cooling water temperature control arrangements be by means of the 3-way thermostat design.

1.14.1.43.2.11.1 HCGS Compliance

Temperature regulation of the HCGS standby diesel engine coolant is accomplished through the use of a "3-way" thermostatic valve.

1.14.1.43.2.12 Recommendation 12 - Concrete Dust Control

Concrete floors tend to shed abrasive dust of sufficient particulate size to not only become airborne, but also to enter electrical cabinets and prevent contact from completely closing. It is recommended that the floors be painted in all rooms which house equipment with electrical contacts.

1.14.1.43.2.12.1 HCGS Compliance

The accumulation of dust, including dust generated from concrete floors and walls, on the electrical equipment associated with the starting of the diesel generators is limited by:

1. Concrete floors are painted in all diesel generator areas which house equipment with electrical contacts.

2. The Auxiliary Building/Diesel Generator Area Ventilation System design and operation which provides filtered air to all diesel generator areas which house equipment with electrical contacts.

3. Plant design which separates each standby diesel generator from other plant equipment and areas.

4. Administrative procedures for cleanliness and ventilation system maintenance.

1.14.1.43.2.13 Recommendation 13 - Mounting and Support of Instrumentation to Protect It From Vibration Damage

It is recommended that instruments, controls, monitors, and indicating elements be supported in or on a freestanding, directly floor mounted panel to the extent functionally practical to reduce vibration induced wear.

1.14.1.43.2.13.1 HCGS Compliance

Except for sensors and other equipment that must be directly mounted on the engine and associated piping, the controls and monitoring instrumentation for the standby diesel generators used at HCGS are installed on freestanding, floor mounted panels separate from the engine skids.

1.14.1.44 Shared DG Conformance To R.G. 1.81, LRG I/PSB-7

1.14.1.44.1 Issue

Shared diesel design must meet position 2 of Regulatory Guide 1.81.

1.14.1.44.2 Response

This issue is not applicable to HCGS since it is a single unit.

1.14.1.45 Periodic Diesel Generator Testing, LRG I/PSB-8

1.14.1.45.1 Issue

Diesel Generator testing once every 18 months as required by Regulatory Guide 1.108.

1.14.1.45.2 Response

Pre-operational and operational testing of the Hope Creek Generating Station standby diesel generators will be in accordance with Regulatory Guide 1.108 Revision 1 and errata dated September 1977.

1.14.1.46 Special Low Power Testing Program, LRG II/1-HFS

1.14.1.46.1 Issue

TMI Action Plan Item I.G.1 indicated the need to supplement operator training by completing a special low power test program. Further clarification of this item includes the need to perform a simulated loss of offsite and onsite ac power.

1.14.1.46.2 Response

See Section 1.10, Item I.G.1, for a discussion of operator training during low power testing. The Nuclear Training Center has formulated and implemented a training program for station blackout. Station Blackout Simulation Training is conducted with the Hope Creek Simulator.

1.14.1.47 Emergency Procedures Reactivity Control Guidelines, LRG II/2-HFS

1.14.1.47.1 Issue

Develop a generic reactivity control guideline which can be utilized for preparing an emergency operating procedure for an anticipated transient without scram (ATWS) event.

1.14.1.47.2 Response

HCGS Emergency Operating Procedure, OP-EO.ZZ-101, Reactor Control, contains the necessary actions to be taken during an ATWS event.

1.14.1.48 Common Reference For Reactor Vessel Level Measurement, LRG II/3-HFS

1.14.1.48.1 Issue

The NRC has asked that a common reference level be established for reactor water level instruments. This is TMI action Item II.K.3.27.

1.14.1.48.2 Response

A common reference point will be established for instruments measuring water level in the reactor vessel. Appropriate design modifications will be implemented by December 1984. See Section 1.10, Item II.K.3.27 for further details.

1.14.1.49 Reactor Coolant Sampling LRG II/1-CHEF

1.14.1.49.1 Issue

In response to TMI Action Item II.B.3, applicants must demonstrate that the locations for post-accident sampling of the reactor coolant will provide samples representative of core conditions. Of specific concern is the potential for dilution of makeup water.

1.14.1.49.2 Response

This issue is addressed in Section 9.3.2. Samples will be obtained from a tap off the jet pump pressure instrument system. Sample representativeness will be assured if there is sufficient core flow to circulate water from the core to the jet pump intake.

After a small break or nonbreak accident, the operator would maintain the reactor water level at or near normal by using emergency procedures. For decay power greater than 1 percent of rated power, it is estimated that the core flow would be greater than 10 percent of the rated flow due to natural circulation. The entire reactor water inventory would be circulated through the jet pumps in about 3 to 4 minutes, thus assuring that representative samples of core coolant will be available at the jet pumps.

At power levels of less than 1 percent of rated power, a representative sample would be obtained by increasing the reactor water level by 18 inches to fully flood the moisture separators and provide a thermally induced recirculation flow path for mixing.

Makeup water would not significantly dilute the sample. Makeup water flow amounts to approximately 2 percent of the core flow for small steam line breaks or nonbreak accidents. For small liquid line breaks, the makeup water flow rate is estimated to be less than 18 percent of the core flow. Thus, no significant dilution would occur, and the water circulating through the jet pump would be representative of reactor coolant inventory for small break or nonbreak accidents.

Furthermore, sample lines in the RHR system provide for a reactor coolant sample when the reactor is depressurized and at least one of the loops of the Residual Heat Removal (RHR) System is operating in the shutdown cooling mode.

For larger line breaks where reactor water level cannot be maintained, reverse flow through the core to the suppression pool is provided. Representative suppression pool samples are obtained from the RHR pump discharge as discussed in Licensing Issue No. 50, see Section 1.14.1.50.

1.14.1.50 Suppression Pool Sampling, LRG II/2-CHEB

1.14.1.50.1 Issue

In response to TMI Action Item II.B.3, applicants must demonstrate the locations for post-accident sampling of the suppression pool will provide samples representative of the pool inventory.

1.14.1.50.2 Response

This issue is addressed in Section 9.3.2. Samples will be taken from the pump discharge from the Residual Heat Removal (RHR) System when the RHR loop is in the suppression pool cooling mode.

The sample lines are installed on the discharge side of the RHR pumps downstream of the pump check valve. Representative samples will be assured by operating the selected RHR loop for approximately 30 minutes prior to taking a sample. Since no SRVs discharge directly into the RHR intake and the locations of the SRV discharge facilitate pool mixing, the suppression pool sample location will provide samples representative of pool inventory.

1.14.1.51 Estimation of Fuel Damage From Post-Accident Samples, LRG II/3-CHEB

1.14.1.51.1 Issue

The NRC Staff required LRG II plants to prepare a procedure for estimating fuel damage from the radionuclide concentration in the reactor coolant and the suppression pool.

1.14.1.51.2 Response

The BWR Owners' Group (BWROG) transmitted to the NRC staff in a June 17, 1983 letter from T. J. Dente (BWROG) to D. G. Eisenhut (NRC), generic procedures for estimating core damage from post-accident measurements of radionuclide concentration in the reactor coolant and the suppression pool and of hydrogen and radiation levels in the containment. During a July 20, 1983 meeting with the BWROG, the NRC staff accepted these generic procedures. Public Service Electric and Gas endorses these generic procedures and will prepare HCGS unique core damage estimation procedures based on the generic procedures.

1.14.1.52 <u>Failures in Vessel Level Sensing Lines Common to Control and Protective Systems, LRG II/1-ICSB</u>

1.14.1.52.1 Issue

The NRC staff is concerned about the failure of a vessel level sensing line that is common to control and protective systems. They have asked the applicants to analyze the consequences of such a failure concurrent with the worst additional single failure in the protective systems or their initiation circuits.

1.14.1.52.2 Response

An analysis was performed to determine the consequences of failure in a vessel level sensing line, common to control and protective circuits, in combination with the worst single failure in a protective channel. The results of this analysis are contained in the response to Question 421.23.

More recently, NRC Generic Letter 92-04 identified that under certain conditions the reference legs can become filled with condensate that contains high levels of dissolved noncondensible gases. If the reactor vessel were to rapidly depressurize these gases would come out of solution causing the dp transmitters to sense a level that would be non conservative. Subsequently, NRC Bulletin 93-03 was issued and stated that as a result of the phenomenon described in the Generic Letter the water level instrumentation may not satisfy GDC 13, 21, 22 and Section 4.20 of IEEE-279. To satisfy the requirements of NRC Bulletin 93-03 a backfill system has been installed.

The backfill system consists of four independent pressure regulating stations, one for each reference leg. Each regulating station is supplied from the CRD system drive water header. Two adjustable orifice valves on each station are used to drop approximately 50 percent of this differential pressure across each valve and to set the backfill flow to approximately 0.50 GPH. Each regulating station also provides backup pressure regulation so that, if the drive water header pressure were to fail high, the backfill flow would be limited. Each pressure regulating station also has a local flow indicating device that assures positive flow into each reference leg. Isolation, bypass, and drain valves are provided for each station to facilitate maintenance and calibration of the components on the regulating station.

The output of each regulating station is connected to 3/8 in. stainless steel tubing routed through the Reactor Building. This tubing is connected to safety related check valves, two in series, for each reference leg. This configuration is the interface for the non safety related backfill tubing and the safety related instrument tubing. These safety related check valves are spring loaded so that a positive dp across the check valves is required for backfill flow into the reference leg. These check valves are connected to the outboard side of the excess flow check valve for each reference leg.

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1.14.1.53 <u>Physical Separation and Electrical Isolation, LRG I/ICSB-2</u>

1.14.1.53.1 Issue

The applicant's design, Class 1E instrumentation do not adhere to adequate separation criteria, have not been qualified, and do not adhere to separation of Class 1E to non-Class 1E instrumentation.

1.14.1.53.2 Response

HCGS complies with Regulatory Guide 1.75 to the extent stated in Section 1.8.75, and therefore this issue is not applicable to HCGS.

1.14.1.54 <u>Redundancy and Diversity of High/Low Pressure System Interlocks, LRG II/2-ICSB</u>

1.14.1.54.1 Issue

During normal and emergency conditions, it is necessary to keep low pressure systems, which are connected to the high pressure Reactor Coolant System, properly isolated from high reactor coolant pressure. Overpressurization of low pressure ECCS lines would increase the potential for the loss of the integrity of the low pressure system. The NRC staff asked for redundant overpressure protection of the low pressure ECCS lines and for independent and diverse interlocks on the valves when two motor operated valves constitute the low pressure/high pressure interface.

1.14.1.54.2 Response

The design of the isolating interlocks for the HCGS low pressure, high pressure interfaces with two motor operated valves (i.e., the intake valves for the Residual Heat Removal System in the shutdown cooling mode) provides for diversity by incorporating:

1. Redundant isolating interlock equipment

2. Separate divisional power and signal sources as well as transmission channels.

3. Diverse installation locations of isolation interlock equipment and by administrating a comprehensive program for monitoring, operating, and testing isolating valves and interlocks.

1.14.1.55 ATWS, LRG I/ICSB-3

1.14.1.55.1 Issue

ATWS

1.14.1.55.2 Response

See response to LRG Issue No. 31, Section 1.14.1.31.

1.14.1.56 Test Techniques, LRG I/ICSB-4

1.14.1.56.1 Issue

In order to perform routine surveillance testing, it is necessary for the applicant to pull fuses. We consider that this design does not satisfy the requirements of IEEE 279-1971, Paragraphs 4.11 and 4.20.

1.14.1.56.2 Response

HCGS does not take exception to paragraphs 4.11 and 4.20 of IEEE 279-1971 and therefore this issue is not applicable to HCGS.

1.14.1.57 Potential for Both Low-Low Setpoint Valves to Open Due to Single Failures, LRG II/3-ICSB

1.14.1.57.1 Issue

In other low-low set designs, single electrical or mechanical failures could allow both low-low setpoint valves to reopen simultaneously or to be open concurrently, potentially defeating the safety design basis.

1.14.1.57.2 Response

SRV low-low setpoint logic is discussed in FSAR Section 7.6.1.6.2.

1.14.1.58 Safety System Setpoints, Instrument Range, LRG I/ICSB-5

1.14.1.58.1 Issue

The NRC staff was concerned that the ranges of the sensors in class 1E systems may be exceeded by the worst-case combination of their setpoints and accuracies.

1.14.1.58.2 Response

The review of safety system setpoints verifies that the sensor ranges are not exceeded by the worst-case combination of setpoints and accuracies. The safety system setpoints provided by GE are being reviewed in the "Instrument Setpoint Methodology Program" described in response to Question 421.18.

1.14.1.59 IE Bulletin 80-06: Engineered Safety Feature Reset Control, LRG II/4-ICSB

1.14.1.59.1 Issue

The NRC staff asked that during the evaluation of compliance with I&E Bulletin 80-06, applicants identify those systems that do not remain in the emergency mode if there is a reset of the actuation signal and that any deviations or proposed design changes be justified.

1.14.1.59.2 Response

This bulletin has been reviewed with respect to the HCGS design. The review indicates that all systems serving safety-related functions do not change modes or status and are returned to normal control after an ESF actuation signal is reset. However, subsequent equipment failures could cause status changes, such as standby or backup systems coming online to maintain the system parameters within the set limits. In short, resetting an ESF signal will not trip any systems off or defeat isolation of containment.

1.14.1.60 <u>Drawings, LRG I/ICSB-6</u>

1.14.1.60.1 Issue

The one line drawings and schematics contradict the functional control drawings and system descriptions which are provided in the FSAR. Furthermore, contact utilization charts contradict the actual schematics.

1.14.1.60.2 Response

For HCGS, the General Electric (GE) functional control drawings are generic in nature and are not updated to show the HCGS' specific design. HCGS plant wiring diagrams are developed from the GE elementaries, system digital logic diagrams, system analog loop diagrams, vendor wiring diagrams, and station one line drawings (where applicable). The HCGS schematics and wiring diagrams are an accurate representation of the engineered design.

1.14.1.61 Control Systems Failure, LRG II/5-ICSB

1.14.1.61.1 Issue

LRG-II plants are required to identify any failures which could result in the malfunctions of more than one control system and show that such failures would not yield consequences beyond those considered in Section 15 nor would require response beyond operator or safety system capability.

1.11.1.61.2 Response

All HCGS safety-related control systems have been designed to satisfy requirements of 10CFR50, Appendix A, General Design Criterion 21, 22, 23, 24, 25, and 29 and IEEE 279-1971, as stated in Section 7.1. By following these standards the HCGS design precludes the possibility of any single failure causing the simultaneous failure or malfunction of more than one safety-related control system.

1.14.1.62 RCIC Classification, LRG I/ICSB-7

1.14.1.62.1 Issue

The NRC staff wanted assurance of the availability of a Seismic Category I water source by an automatic switchover to the suppression pool upon failure of the condensate storage tank.

1.14.1.62.2 Response

See response to LRG Issue No. 6, Section 1.14.1.8.

1.14.1.63 <u>Safety-Related Display, LRG I/ICSB-9</u>

1.14.1.63.1 Issue

The design of safe shutdown systems of LRG-I/II plants must satisfy the requirements of IEEE 279-1971, Paragraph 4.10.

1.14.1.63.2 Response

HCGS control and instrumentation systems important to safety are designed to satisfy the requirements of IEEE 279-1971. HCGS takes no exception to paragraph 4.10 of IEEE 278-1971, therefore this issue is not applicable to HCGS.

1.14.1.64 <u>Rod Block Monitor LRG I/ICSB-10</u>

1.14.1.64.1 Issue

Section 7.7 of the FSAR indicates that the Rod Sequence Control System (RSCS) is utilized to restrict rod worths for the design basis rod drop accident and the rod block monitor (RBM) is utilized to prevent erroneous withdrawal of control rods to prevent local fuel damage. The NRC staff asked for the rationale and basis for not including these systems or portions of these systems as safety-related and for a discussion of their interfaces with safety-related portions of the design (e.g., average power range monitor (APRM), refueling interlocks, etc.).

1.14.1.64.2 Response

The Rod Worth Minimizer (RWM) acts to prevent withdrawal of an out of sequence control rod, to prevent an erroneous continuous control rod withdrawal during reactor startup, and to minimize the core reactivity transient during a rod drop accident. The consequences of a rod withdrawal error in the startup range are analyzed in Appendix 15.B where it is demonstrated that the licensing basis criterion for fuel failure is still satisfied even when the RWM fails to block rod withdrawal. Thus, the RWM and the Manual Control System (RMCS) are not safety-related. The safety action required for the continuous control rod drop incident (a reactor scram) is provided by the safety related intermediate range monitor (IRM) subsystem of the Neutron Monitoring Systems (NMS). If the setpoint that trips a core flux scram is reached during a flux transient, the IRM will both block further rod withdrawal and initiate a scram. Furthermore, a second safety related NMS scram trip, supplied by the APRM, can terminate the core power transient.

The RWM does not interface with safety-related systems. Refueling interlocks are not considered safety-related.

The rod block monitor is designed to prohibit erroneous withdrawal of a control rod during operation at core high power levels. This prevents local fuel damage under permitted bypass and/or detector chamber failure in the local power range monitor (LPRM), and prevents local fuel damage during a single rod withdrawal error. Local fuel damage poses no significant threat relative to radioactive release from the plant.

Although the RBM does not perform a safety-related function, in the interest of plant economics and availability, it is designed to meet certain salient design principles of a safety system. These include the following:

1. Redundant, separate, and isolated RBM channels.

2. Redundant, separate, and isolated rod selection information, including isolated contacts for each rod selection pushbutton providing input to each RBM channel.

3. Independent, isolated RBM level readouts and status displays from the RBM channel.

4. A mechanical barrier between Channels A and B of the manual bypass switch.

5. Multiple manual RBM channel bypass prohibited by switch design.

6. Independent, separate, isolated rod block signals from the RBM channels to the RMCS circuitry.

7. Fail safe design, since loss of power initiates a rod block.

8. Initiation of a rod block by trip of either RBM channel

The RBM interfaces with the following safety-related systems:

1.	LPRM:	LPRM signal information is provided to each RBM channel from either the APRM instrument or LPRM instrument for each division via fiber optic link.
2.	Flow Signal:	Recirculation flow inputs are provided to the RBM from either the APRM instrument or LPRM instrument for each division via fiber optic link for trip reference.
3.	APRM System:	Independent, separate, and isolated APRM reference signals are supplied to each RBM channel for trip reference.

(Historical Information)

1.14.1.65 MSIV Leakage Control System, LRG I/ICSB-11

1.14.1.65.1 Issue

We identified a single failure to the MSIV Leakage Control System which could lead to possible failure of the system during testing or operation.

1.14.1.65.2 Response

The MSIV Sealing System is capable of performing its function following a LOCA concurrent with an assumed single active failure including failure of any one of the MSIVs to close. The MSIV Sealing System is discussed in Section 6.7 and its instrumentation and controls are covered in Section 7.3.

1.14.1.66 Procedures Following Bus Failure (IE Bulletin 79-27), LRG II/6-ICSB

1.14.1.66.1 Issue

IE Bulletin 79-27 requires all LRG-II plants to provide cold shutdown procedures to be followed upon loss of a non-Class 1E instrumentation and control bus during plant operation.

1.14.1.66.2 Response

Procedures will be used by control room operators to achieve cold shutdown conditions upon loss of power to each Class 1E and non-Class 1E bus supplying power to safety and non safety-related instrument and control bus. Procedures are available for review.

1.14.1.67 Harsh Environment For Electrical Equipment Following High Energy Line Breaks, LRG II/7-ISCB

1.14.1.67.1 Issue

LRG-II plants need to perform a review to determine any required design changes or operator actions necessary to assure that high energy line breaks would not cause control systems malfunction and complicate the event beyond the existing FSAR analysis.

1.14.1.67.2 Response

HCGS has performed a plant specific review of all safety-related areas with regard to high energy line break. The hazards considered in high energy line break analysis (HELBA) are pressurization, temperature, pipe whip, flooding and jet impingement. All components, that are required to operate for pipe break mitigation (PBOC, PBIC) are either qualified for the harsh environment or rerouted or relocated to avoid the harsh environment. If the above alternatives are not possible, the components are to be modified (more supports, protective shields, or upgrade component material, etc.,) to withstand the harsh environment.

1.14.1.68 Steam Bypass of the Suppression Pool, LRG I/CSB-1

1.14.1.68.1 Issue

The applicant's approach to suppression pool bypass is not consistent with Branch Technical Position CSB 6-5. The applicant must commit to perform a lower power surveillance leakage test of the containment during refueling outage.

1.14.1.68.2 Response

HCGS commitments to a drywell to suppression chamber bypass test discussed in Section 6.2.6.

1.14.1.69 Pool Dynamic LOCA and SRV Loads, LRG I/CSB-2

1.14.1.69.1 Issue

The large scale testing of an advanced design pressure-suppression containment, and the in-plant testing of Mark containments identified new suppression pool hydrodynamic loads that had not been explicitly accounted for in the original Mark I containment system design. The new loads resulted from postulated loss-of-coolant accident and safety/relief valve operation. Because these hydrodynamic loads had not been considered in the original design basis of the Mark I containment system, a detailed reevaluation of Mark I containment design is required to restore the originally intended design safety margins.

1.14.1.69.2 Response

HCGS FSAR Appendix 3B contains a summary of the plant unique analysis of the HCGS containment. It was performed in accordance with the requirements of the NUREG-0661, and demonstrates that the HCGS primary containment meets the acceptance criteria of NUREG-0661.

The original Hope Creek SRVs were Target Rock 2-Stage SRVs, and the plant unique analysis summarized in Appendix 3B was prepared for the 2-Stage SRVs. Target Rock 3-Stage SRVs have been evaluated and approved for installation at Hope Creek. The Plant Unique Analysis does not require revision for installation of 3-Stage SRVs. The 3-Stage SRVs have the same set pressures, capacity and response time as the 2-Stage SRVs. They also utilize the same main valve body as the 2-Stage SRV, with minor modification.

1.14.1.70 Containment Dynamic Loads, LRG II/1-CSB

1.14.1.70.1 Issue

LRG-II plants must use NRC approved containment load definitions as the basis for containment dynamic load evaluations.

LRG-II plants must demonstrate that previous tests are applicable or must commit to perform in-situ safety/relief valve (SRV) tests.

The original Hope Creek SRVs were Target Rock 2-Stage SRVs. Target Rock 3-Stage SRVs have been evaluated and approved for installation at Hope Creek. Confirmatory in-situ tests were not repeated when the 3-Stage Target Rock SRVs were approved for installation because they have the same set pressures, capacity and response times as the original 2-Stage SRVs.

1.14.1.70.2 Response

HCGS is using NRC approved containment load definitions (NUREG-0661) as the basis for containment dynamic load evaluations with certain exceptions, identified in Appendix 3B. Hope Creek intends to perform confirmatory in-situ SRV tests.

1.14.1.71 Containment Purge System, LRG I/CSB-3

1.14.1.71.1 Issue

Containment purge systems often have small vent lines that are used to bleed off excess primary containment pressure during normal operation. Because the lines provide an open path from the containment to the environs, they must be evaluated against the requirements of Branch Technical Position CSB 6-4.

1.14.1.71.2 Response

The Containment Inerting and Purge System (CIPS) is designed to purge the primary containment prior to and during outages. The Containment Prepurge Cleanup System (CPCS) is designed to reduce the level of atmospheric halogen radioactivity to within radiological effluent Technical Specification limits, as required, prior to purging the primary containment. The requirements outlined in BTP CSB 6-4 pertain to the use of CIPS/CPCS during normal power operation. During normal operation the 6-, 24-, and 26-inch containment isolation valves will be administratively controlled to assure that they are not opened except as permitted by the Technical Specifications.

To relieve the initial containment pressure buildup caused by the temperature increase during reactor power ascension and to reduce pressure as required during other normal operating transients, the first containment isolation valve from the drywell and/or suppression chamber may be opened in accordance with the Technical Specifications to permit the use of the 2-inch vent lines that bypass the second isolation valve.

The frequency of operation of the 2-inch bypass vent paths used to reduce containment pressure during normal plant operation will depend on operating experience at HCGS. The operator will open the 2-inch bypass vent paths if the drywell normal operating pressure approaches the technical specification limit.

The containment isolation valves and the bypass lines are shown on Plant Drawing M-57-1.

The following is an evaluation of CIPS/CPCS with respect to the criteria specified in BTP CSB 6-4, when used during normal power operation. The evaluation is keyed to the criteria of BTP CSB 6-4.

1.14.1.71.2.1 Criterion 1.a

The reliability and performance capabilities of the containment isolation valves should be commensurate with the importance to safety of isolating the system penetrating the primary containment boundary.

1.14.1.71.2.1.1 Response

The CIPS/CPCS isolation valves, bypass vent valve, and interconnecting piping are designed as ASME Section III, Class 2 components. The design criteria for these components include the pressure, temperature, flow, and other environmental conditions associated with closure following a DBA in the containment. Therefore, the HCGS design complies with this criterion.

1.14.1.71.2.2 Criterion 1.b

The number of supply and exhaust lines should be limited to one supply line and one exhaust line to improve the reliability of the isolation function.

1.14.1.71.2.2.1 Response

Only one supply line and one exhaust line may be open at any given time during power operation, startup, or hot shutdown, as required, in accordance with the Technical Specifications.

1.14.1.71.2.3 Criterion 1.c

The size of the vent lines should not exceed 8 inches in diameter.

1.14.1.71.2.3.1 Response

The radiological analysis presented in Section 1.14.1.71.2.11.1 justifies the use of 26-inch purge supply and exhaust lines with the purge valves closing within 5 seconds, including an assumed 1-second instrument time delay, of the onset of a LOCA.

1.14.1.71.2.4 Criterion 1.d

The containment isolation provisions for the purge system lines should meet the appropriate standards of engineered safety features.

1.14.1.71.2.4.1 Response

The isolation provisions for the CIPS/CPCS fully comply with the required standards of an engineered safety feature. The redundant isolation valves and the bypass vent valve are designed to Seismic Category I standards, classified as Quality Group B, protected from missiles, and are powered and actuated by diverse means, thus allowing them to accommodate a single failure.

1.14.1.71.2.5 Criterion 1.e

The instrumentation and control systems provided to isolate the vent system lines should be independent and actuated by diverse parameters. Motive power to close the isolation valves should also be from diverse sources.

1.14.1.71.2.5.1 Response

The instrumentation and controls provided to isolate the CIPS/CPCS vent path comply with the stated criterion.

1.14.1.71.2.6 Criterion 1.f

The isolation valve closure times should not exceed 5 seconds to facilitate compliance with 10CFR100.

1.14.1.71.2.6.1 Response

The isolation valve maximum closure time is 5 seconds, including instrument delay time.

1.14.1.71.2.7 Criterion 1.g

Provisions should be made to ensure that isolation valve closure will not be prevented by debris which could potentially become entrained in the escaping air and steam.

1.14.1.71.2.7.1 Response

Debris protection for the containment vent and purge lines is discussed in Section 6.2.4.3.2.1. It is also unlikely that any debris will be thrown directly into the vent line opening since there is only one high energy line in the immediate vicinity of the containment penetration and any postulated breaks in it will not be favorably oriented to project any debris into the opening.

1.14.1.71.2.8 Criterion 2

The purge system should not be relied on for temperature and humidity control.

1.14.1.71.2.8.1 Response

The purge system and the bypass vent path are not relied on for temperature and humidity control within the containment. The drywell coolers perform this function.

1.14.1.71.2.9 Criterion 3

Containment atmosphere cleanup systems should be provided within containment to minimize the need for purging.

1.14.1.71.2.9.1 Response

The containment prepurge cleanup system, located in the Reactor Building, is connected to the primary containment, as shown on Plant Drawings M-57-1 and M-76-1, and is used for cleanup prior to reactor shutdown, as required. Location of the CPCS within the primary containment is not practical for a BWR Mark I containment. Operation of the CPCS will be limited to the minimum time necessary to allow purging of the primary containment and only when deinerting of the primary containment is planned (see Section 6.2.5.2.1).

1.14.1.71.2.10 Criterion 4

Provisions should be made for testing the availability of the isolation function and the leakage rate during reactor operation.

1.14.1.71.2.10.1 Response

Operation of individual actuators can be independently verified during normal operation. Provisions have also been made to perform leakage rate tests during reactor operation.

1.14.1.71.2.11 Criterion 5.a

An analysis of the radiological consequences of a LOCA should be performed. Radiological consequences should be within 10CFR50.67 limits.

(Historical Information)

1.14.1.71.2.11.1 Response

An analysis of the radiological consequences associated with a LOCA occurring while operating the CIPS/CPCS has been performed. The resultant site boundary dose to the thyroid, which is the most limiting dose due to the purge duct alone, is 1.5×10^{-2} rem. Dose impact due to tritium and particulate release is considered negligible. This dose is a very small fraction of the 10CFR100 guideline value of 300 rem - thyroid. The resultant dose is based on the realistic release assumptions given in BTPCSB 6-4 (SRP 6.2.4) for showing acceptable purge valve closure times. The analysis assumes that the drywell purge supply and exhaust valves are open when the LOCA occurs. These valves take 5 seconds to close following a LOCA (including instrument delay time), and the releases are assumed to be unfiltered. Specifically, the analysis assumes a 1-second instrument delay time and a 4-second valve stroke time totaling 5 seconds, including instrument delay. This analysis bounds the case of a LOCA occurring when the 2-inch bypass vent valves are open and the outboard isolation valves are closed. The total mass released is 1694 pounds.

1.14.1.71.2.12 Criterion 5.b

Protection of safety-related equipment downstream of the vent path isolation valves shall be provided to prevent the effects of a LOCA from adversely affecting their ability to function.

1.14.1.71.2.12.1 Response

The effects of a LOCA, with the purge isolation valves open, on the safety-related equipment downstream of the valves has been analyzed and evaluated. The FRVS fan and filter units are normally isolated from the RBVS ducts and are not used during cleanup or purge operations. Blowout panels have been added to the CPCS ducts before the RBVS/FRVS isolation dampers. These blowout panels limit the pressure pulse in the ducts required for FRVS operation. The integrity of the FRVS ducts and equipment due to the resulting pressurization was verified. The FRVS air handling units are individually isolated from the ducts on the inlet and outlet by dampers at the fan/filter units. These dampers will remain closed during the pressure pulse due to a LOCA during purging. The pressure pulse will have ended before the FRVS fans are started.

The effects of steam release during the blowdown also were evaluated. The evaluation verified that the steam will not adversely affect the performance of the FRVS.

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1.14.1.71.2.13 Criterion 5.c

The effects on ECCS of a loss of containment atmosphere through the containment purge during a LOCA should be analyzed.

1.14.1.71.2.13.1 Response

There will be no significant reduction in containment pressure resulting from the blowdown. Furthermore, this reduction would have no effect on ECCS performance, since the ECCS pumps are sized for atmospheric suction pressure. No credit is taken for containment pressure acting on the pump suction.

1.14.1.71.2.14 Criterion 5.d

The maximum allowable leak rate of the purge isolation valves shall be specified based on proper consideration of valve size, allowable containment leakage, and bypass leakage limitations (if applicable).

1.14.1.71.2.14.1 Response

Leakage rates on the purge and vent isolation valves are based on complying with the limits established by the HCGS Technical Specifications, 10CFR50, Appendix J, and the Primary Containment Leakage Rate Testing Program, and are periodically tested to verify their performance.

1.14.1.71.3 Summary

As discussed above, the HCGS purge supply and exhaust valves comply, to the maximum extent practical, with the criteria of BTP CSB 6-4. When coupled with the extremely unlikely event of a LOCA occurring while the drywell or suppression chamber valves are open, it is concluded that an adequate safety design exists for limited operation of the CIPS/CPCS during modes other than cold shutdown or refueling.

1.14.1.72 Combustible Gas Control, LRG I/CSB-4

1.14.1.72.1 Issue

The proposed Combustible Gas Control System is designed in accordance with the requirements of 10CFR50.14, we require the applicant to commit to the following:

1. When the containment pressure is above 15.3 psig and the hydrogen concentration is 3.3 volume percent, the Containment Spray System must be actuated to reduce the containment pressure.

2. Following a LOCA, the recombiner system becomes an extension of the containment boundary. We require the applicant to demonstrate the leaktight integrity of the recombiner system.

3. Applicants for which the recombiner system design pressure is less than the predicted containment design pressure; the applicants commit to actuate the containment spray system as listed on the individual docket.

4. Applicants agree to perform system leak tests.

1.14.1.72.2 Response

1. The HCGS FSAR Section 6.2 does not postulate containment pressure greater than 15.3 psig concurrent with hydrogen concentration greater than or equal to 3.3 volume percent. Even without containment spray, Figure 6.2-7 (Case C) shows that 15.3 psig containment pressure (after the initial spike) occurs at 8.33 hours. While Figure 6.2-32 shows hydrogen concentration of 3.3 volume percent is not reached until approximately 36 hours.

Therefore, assuming the pressure remains above 15.3 psig, the operator has more than 27 hours to actuate the containment spray. The containment spray will quickly lower the containment pressure below that required for recombiner operation.

2. The recombiner system is designed and inspected in accordance with ASME Section III, Class 2 requirements. Prior to installation, the recombiners will be shown to have no detectable leakage, using soap solution, when tested in accordance with Article NC-6300 of the ASME Section III B&PV Code. Valve stems and gasketed flange joints are exempted from this test.

   Additionally, the complete recombiner unit (including valve stems and gasketed flange joints) shall have a leak rate equal to or less than 0.5 standard cubic centimeters per second (standard conditions are 68°F and 14.7 psia) when tested at a pressure equal to or greater than 30 psia.

   Section 6.2.5.4 and Section 1.10, Position III.D.1.1 refer to additional test requirements.

3. The HCGS recombiner design pressure equals the containment design pressure. Reference Table 6.2-17.

4. See response to Item 2 above.

1.14.1.73 <u>Hydrogen Control Capability, LRG II/2-CSB</u>

1.14.1.73.1 Issue

Provide a description of the program to improve the hydrogen control capability.

The program should include:

1. A description of the system the plants propose to install

2. The installation schedule

3. Its design bases

4. Research programs (including schedules) designed to demonstrate and/or confirm efficacy of the proposed system.

1.14.1.73.2 Response

Section 6.2.5 describes the current proven design which assures control of postulated hydrogen generation with the following major features:

1. Inerted containment

2. Redundant safety-related containment hydrogen recombiners.

3. Redundant safety-related hydrogen/oxygen analyzers.

1.14.1.74 Containment Leakage Testing, LRG I/CSB-5

1.14.1.74.1 Issue

Detailed information is required to demonstrate compliance with 10CFR50, Appendix J and to evaluate any exceptions.

1.14.1.74.2 Response

Compliance with Appendix J is discussed in Section 6.2.6. Exceptions are identified in Table 6.2-26 and justified in the footnotes.

1.14.1.75 BWR Scram Discharge Volume Modifications LRG II/1-ASB

1.11.1.75.1 Issue

The Control Rod Drive Hydraulic System (CRDHS) should conform to the Scram Discharge System design criteria enumerated in the generic Safety Evaluation Report (SER), BWR Scram Discharge System, dated December 1, 1980.

1.14.1.75.1.1 Response

HCGS complies with the criteria enumerated in the generic Safety Evaluation Report, BWR Scram Discharge System.

The criteria given in the referenced SER are organized according to; 1) functional, 2) safety, 3) operational, 4) design and 5) surveillance criteria. A summary of each criteria is given below along with a discussion of HCGS CRDHS compliance.

1.14.1.75.2 Functional Criteria

1.14.1.75.2.1 Functional Criterion 1

The scram discharge volume (SDV) shall have sufficient capacity to receive and contain water exhausted by a full reactor scram without adversely affecting control-rod-drive scram performance.

1.14.1.75.2.1.1 Response

A minimum scram discharge volume of 3.34 gallons per drive is provided. This minimum scram discharge volume is based on conservative assumptions as to the performance of the scram system. In the event of a coolant leak into the SDV, an automatic scram will occur before the SDV's available volume is threatened.

1.14.1.75.2.2 Safety Criteria

1.14.1.75.2.2.1 Safety Criterion 1

No single active failure of a component or service function shall prevent a reactor scram, under the most degraded conditions that are operationally acceptable.

1.14.1.75.2.2.1.1 Response

No single active failure in the HCGS scram system design will prevent a reactor scram. The Scram Discharge System design meets the NRC acceptance criterion for Safety Criterion 1. Partial or full loss of service functions will not adversely affect the scram system function or will result in a full reactor scram. There are no reductions in the pipe size of the header piping going from the hydraulic control units (HCUs) to and including the scram discharge instrument volume (SDIV). This hydraulic coupling permits operability of the scram level instrumentation prior to loss of system function. The scram level instrumentation are redundant and diverse to assure no single active failure or common mode failure prevents a reactor scram.

1.14.1.75.2.2.2 Safety Criterion 2

No single active failure shall prevent an uncontrolled loss of reactor coolant.

1.14.1.75.2.2.2.1 Response

Redundant scram discharge volume (SDV) vent and drain valves are a part of the HCGS design. The redundant SDV valve configuration shown in Plant Drawing M-47-1 assures that no single active failure can result in an uncontrolled loss of reactor coolant. An additional solenoid operated pilot valve controls the redundant vent and drain valves. The vent and drain system is sufficiently redundant to avoid a failure to isolate the SDV due to solenoid failure. The opening and closing sequences of the vent and drain valves are controlled to minimize excessive hydrodynamic forces.

1.14.1.75.2.2.3 Safety Criterion 3

The Scram Discharge System instrumentation shall be designed to provide redundancy, to operate reliably under all conditions, and shall not be adversely affected by hydrodynamic forces or flow characteristics.

1.14.1.75.2.2.3.1 Response

Diverse, and redundant level sensing instrumentation is provided for the automatic scram function. SDIV water level is measured by utilization of both float switches and differential pressure sensing devices. All instrument taps are located on the SDIV to protect the level sensing instrumentation from the flow dynamics in the Scram Discharge System. Each SDIV has a redundant instrument loop. A one-out-of-two taken twice logic is employed for the automatic Scram function. This instrumentation arrangement assures the automatic scram function on high SDIV water level in the event of a single active or passive failure.

1.14.1.75.2.2.4 Safety Criterion 4

System operating conditions which are required for scram shall be continuously monitored.

1.14.1.75.2.2.4.1 Response

Continuous and reliable signals are monitored to detect unsatisfactory SDIV water levels and to provide indication of such to the operator. Sensors monitoring the SDIV level provide alarm and scram signals that are displayed in the main control room. See the response to Safety Criterion 3 (Section 1.14.1.75.2.2.3.1).

1.14.1.75.2.2.5 Safety Criterion 5

Repair, replacement, adjustment, or surveillance of any system component shall not require the scram function to be bypassed.

1.14.1.75.2.2.5.1 Response

The SDIV scram level instrumentation arrangement and trip logic allows instrument adjustment or surveillance without bypassing the scram function or directly causing a scram. Each level instrument can be individually isolated without bypassing the scram function. A one-out-of-two taken twice trip logic is employed. The HCGS Technical Specifications will ensure that the scram function is not bypassed during repair, replacement, adjustment or surveillance of any system component.

1.14.1.75.2.3 Operational Criteria

1.14.1.75.2.3.1 Operational Criterion 1

Level instrumentation shall be designed to be maintained, tested, or calibrated during plant operation without causing a scram.

1.14.1.75.2.3.1.1 Response

The HCGS design provides for half-scram conditions during maintenance, testing or calibration during plant operation. See the response to Safety Criteria 5 (Section 1.14.1.75.2.2.5.1).

1.14.1.75.2.3.2 Operational Criterion 2

The system shall include sufficient supervisory instrumentation and alarms to permit surveillance of system operation.

1.14.1.75.2.3.2.1 Response

Supervisory instrumentation and alarms such as accumulator trouble, scram valve air supply low pressure, and SDV not drained alarms, are adequate and permit surveillance of the scram system's readiness.

1.14.1.75.2.3.3 Operational Criterion 3

The system shall be designed to minimize the exposure of operating personnel to radiation.

1.14.1.75.2.3.3.1 Response

Minimizing the exposure of operating personnel to radiation is a consideration in the design and location of all plant equipment.

1.14.1.75.2.3.4 Operational Criterion 4

Vent paths shall be provided to assure adequate drainage in preparation for scram reset.

1.14.1.75.2.3.4.1 Response

A vent line is provided as part of the Scram Discharge System to assure proper drainage in preparation for scram reset. HCGS provides a dedicated vent line with a nonsubmerged discharge into one of the Reactor Building equipment drain sumps. The sumps are vented to the atmosphere. Furthermore, additional vent capability is provided by the vent line vacuum breaker. The vacuum breaker has a differential pressure operating setpoint of 0.2 psid (5.5 inches of water).

1.14.1.75.2.3.5 Operational Criterion 5

Vent and drain functions shall not be adversely affected by other system interfaces. The objective of this requirement is to preclude water backup in the scram instrument volume which could cause spurious scram.

1.14.1.75.2.3.5.1 Response

The SDV vent and drain lines are dedicated lines that discharge into the Reactor Building equipment drain sump as shown on Plant Drawing M-61-0. A vacuum breaker on the SDV vent line and shutoff valves on the SDV vent and drain lines preclude water from siphoning back into the SDIV from the equipment drain sump.

1.14.1.75.2.4 Design Criteria

1.14.1.75.2.4.1 Design Criterion

The scram discharge headers shall be sized in accordance with GE Operation Experience Report No. 54 and shall be hydraulically coupled to the instrumented volume(s) in a manner to permit operation of the scram level instrumentation prior to loss of system function. Each system shall be analyzed based on plant specific maximum in-leakage to ensure that the system function is not lost prior to initiation of automatic scram. Maximum in-leakage is the maximum flow rate through the scram discharge line without control rod motion, summed over all control rods. The analysis should show no need for vents or drains.

1.14.1.75.2.4.1.1 Response

As discussed in response to Functional Criterion 1, a minimum SDV of 3.34 gallons per drive is specified in the system design specifications. Furthermore, there is good communication between the scram discharge header and the SDIV. There are no reductions in the pipe size of the header piping from the HCUs to and including the SDIV. The SDIV is directly connected to the scram discharge volume at the low point of the scram discharge header piping.

1.14.1.75.2.4.2 Design Criterion 2

Level instrumentation shall be provided for automatic scram initiation while sufficient volume exists in the scram discharge volume.

1.14.1.75.2.4.2.1 Response

The SDV size and SDV instrumentation assures automatic scram initiation while there is sufficient scram discharge volume remaining to accept the water discharged during a scram. See response to Functional Criteria 1 and Design Criteria 1 (Section 1.16.1.75.2.1.1 and 1.16.1.75.2.4.1.1).

1.14.1.75.2.4.3 Design Criterion 3

Instrumentation taps shall be provided on the vertical instrument volume and not on the connected piping.

1.14.1.75.2.4.3.1 Response

All instrument taps are located on the SDIV. See response to Safety Criterion 3 (Section 1.14.1.75.2.2.3.1).

1.14.1.75.2.4.4 Design Criterion 4

The scram instrumentation shall be capable of detecting water accumulation in the instrumented volume(s) assuming a single active failure in the instrumentation system or the plugging of an instrument line.

1.14.1.75.2.4.4.1 Response

HCGS provides redundant instrumentation and redundant instrument sensing lines. See response to Safety Criterion 3 (Section 1.14.1.75.2.2.3.1).

1.14.1.75.2.4.5 Design Criterion 5

Structural and component design shall consider loads and conditions including those due to fluid dynamics, thermal expansion, internal pressure, seismic considerations and adverse environments.

1.14.1.75.2.4.5.1 Response

The SDV and associated vent and drain piping is classified as safety-related and meets the ASME Section III, Class 2 and Seismic Category I requirements. It is designed for maximum postulated temperatures and internal pressure conditions. Dynamic transient loading is still being evaluated. PSE&G is participating in the BWROG investigation into fluid dynamic phenomenon in the SDV.

See Section 3.11 for discussion of environmental qualification of SDV instrumentation and components.

1.14.1.75.2.4.6 Design Criterion 6

The power operated vent and drain valves shall close under loss of air and/or electric power. Valve position indication shall be provided in the main control room.

1.14.1.75.2.4.6.1 Response

SDV vent and drain valves close on loss of air and/or electrical power, and position indication is provided in the main control room.

1.14.1.75.2.4.7 Design Criterion 7

Any reductions in the system piping flow path shall be analyzed to assure system reliability and operability under all modes of operation.

1.14.1.75.2.4.7.1 Response

Reductions in the piping flow path between the SDV headers and SDIVs have not been analyzed because there are no piping restrictions between the SDV headers and SDIVs.

1.14.1.75.2.4.8 Design Criterion 8

System piping geometry (i.e., pitch, line size, orientation) shall be such that the system drains continuously during normal plant operation.

1.14.1.75.2.4.8.1 Response

All SDV piping is continuously sloped from its high point to its low point to facilitate system drainage.

1.14.1.75.2.4.9 Design Criterion 9

Instrumentation shall be provided to aid the operator in the detection of water accumulation in the instrumented volume(s) prior to scram initiation.

1.14.1.75.2.4.9.2 Response

There are three different water levels in the SDIV that are monitored. At the lowest level, a level monitor provides an alarm in the main control room to indicate that the SDIV is not completely empty during post-scram draining, or to indicate that the volume has started to fill through leakage accumulation during reactor operation. At the second level, a level monitor provides a rod withdrawal block to prevent further withdrawal of any control rod. The third level initiates a reactor scram.

1.14.1.75.2.4.10 Design Criterion 10

Vent and drain line valves shall be provided to contain the scram discharge water, with a single active failure and to minimize operational exposure.

1.14.1.75.2.4.10.1 Response

The redundant vent and drain valve configuration assures that no single active failure can result in uncontrolled releases of radioactivity to the environs.

1.14.1.75.2.5 Surveillance Criteria

1.14.1.75.2.5.1 Surveillance Criterion

Vent and drain valves shall be periodically tested.

1.14.1.75.2.5.1.1 Response

Surveillance procedures are provided to periodically demonstrate operability of the SDV vent and drain valves in accordance with HCGS Technical Specification 4.1.3.1.1.

1.14.1.75.2.5.2 Surveillance Criterion 2

The SDV level detection instrumentation shall be periodically tested in place.

1.14.1.75.2.5.2.1 Response

Level detection instrumentation will be periodically tested in place in accordance with HCGS Technical Specification 4.3.1.1.

1.14.1.75.2.5.3 Surveillance Criterion 3

The operability of the entire system as an integrated whole shall be demonstrated periodically and during each operating cycle, by demonstrating scram instrument response and valve function at pressure and temperature at approximately 50 percent control rod density.

1.14.1.75.2.5.3.1 Response

Periodic operability demonstration of the system as an integrated whole will be in accordance with HCGS Technical Specification 4.1.3.1.4. Additionally, SDV functional testing, and calibration of the SDV water level will be performed in accordance with the frequency specified in HCGS Technical Specification Table 4.3.1.1-1.

1.14.1.76 Safe Shutdown for Fires and Remote Shutdown System, LRG II/2-ASD

1.14.1.76.1 Issue

Demonstrate compliance with Sections III.G and III.L of Appendix R.

1.14.1.76.2 Response

See HCGS FSAR Appendix 8A for a description of compliance to Appendix R.

1.14.1.77 Protection of Equipment in Main Steam Pipe Tunnel LRG II/3-ASB

1.14.1.77.1 Issue

It is required that the compartment in the Auxiliary Building between the containment and the Turbine Building which houses the main steam lines and feedwater lines and their isolation valves, be designed to consider the environmental effects (pressure, temperature, humidity) and potential flooding consequences from an assumed crack, equivalent to the flow area of a single ended pipe rupture in these lines.

It is also required that if this assumed crack could cause the structural failure of this compartment, then the structural failure should not jeopardize the safe shutdown of the plant. Finally, it is required that essential equipment located within the compartment, including the main steam isolation and feedwater valves and their operators be capable of operating in the environment resulting from the above crack.

1.14.1.77.2 Response

Pipe breaks in the main steam tunnel are discussed in Section 3.6 of the HCGS FSAR. A pipe break inside the main steam tunnel will not cause failure of the structure due to overpressurization, because of blowout panels (discussed in Section 3.6.1), nor due to flooding, because the structure is designed for internal flooding, as discussed in Section 3.4.

Environmental Qualification (EQ) of components located in the main steam tunnel is being addressed, as stated in Section 3.6. The HCGS environmental qualification program is described in Section 3.11.

1.14.1.78 Design Adequacy of the RCIC System Pump Room Cooling Systems, LRG II/4-ASB

1.14.1.78.1 Issue

TMI Action Plan Item II.K.3.24 identified the need to confirm the adequacy of the RCIC System Pump Room Cooling System to maintain allowable room temperature for at least two hours during a loss of offsite power event.

1.14.1.78.2 Response

The HCGS response to TMI Action Plan Item II.K.3.24 is provided in Section 1.10.2 of the HCGS FSAR.

1.14.1.79 Reassessment of Accident Assumptions as Related to Main Steam Line Isolation Valve Leakage Rate, ILRG II/1-AEB

1.14.1.79.1 Issue

Proposed technical specification limits for main steam line isolation valves (MSIV) which are greater than 11.5 SCFH may increase potential offsite doses significantly. A reassessment of accident consequences is required to justify a higher limit.

1.14.1.79.2 Response

Operational requirements are imposed on the MSIV sealing system which allow MSIV leakage rates up to 11.5 SCFH for each inboard. MSIV in each main steam line. See Section 6.7 for further details.

The MSIV leakage rate has been raised to 150 SCFH and the MSIV Sealing System was removed from the plant. The above Issue and Response is retained for historical purposes only.

1.14.1.80 Asymmetrical LOCA and SSE and Annulus Pressurization Loads on Reactor, Vessel, Internals and Supports, LRG I/MEB-1

1.14.1.80.1 Issue

Document your reevaluation of the safety-related systems and components based upon the load combinations, response combination methodology, and acceptance criteria required by us as presented at our meeting of December 12, 1978. (Reference letter dated September 18, 1978).

1.14.1.80.2 Response

The load combination of normal operating loads, plus operating basis earthquake and the simultaneous actuation of all safety/relief valves is applicable to GE Mark II plants only.

The load combination of normal operating loads plus annulus pressurization plus safe shutdown earthquake has been considered by HCGS.

1.14.1.81 Pre-Operational Vibration Assurance Program, LRG I/MEB-2

1.14.1.81.1 Issue

Additional information is required concerning the basis for the allowable vibration amplitudes derived.

1.14.1.81.2 Response

HCGS preoperation vibration assurance program, including acceptance criteria is described in Section 3.9.2.

1.14.1.82 RPV Internals Vibration Test Program For BWR/6, LRG II/2-MEB

1.14.1.82.1 Issue

Explain how LRG II plants will document their RPV internals testing. In particular, will a licensing topical report similar to that submitted for BWR 4/5, NEDE-24057, be submitted?

1.14.1.82.2 Response

HCGS is a BWR 4 and appropriate documentation is provided by Licensing Topical Report NEDE-24057-P, as discussed in Section 3.9.2.6.

1.14.1.83 Dynamic Response Combination Using SRSS Technique, LRG I/MEB-3

1.14.1.83.1 Issue

We are studying the problem of utilizing the square root of the sum of the squares (SRSS) for determining dynamic responses other than LOCA and SSE as you have used. By not utilizing the absolute sum method, the review may be extended if we do not agree that the SRSS methodology is applicable.

1.14.1.83.2 Response

HCGS is using absolute sum for determining dynamic responses other than LOCA and SSE except for ASME B&PV Code Class 1, 2 and 3 non-NSSS components and supports. For load combination tables for these components and supports, refer to Tables 3.9-8 and 3.9-21, respectively.

1.14.1.84 Input Criteria for Use of SRSS for Mechanical Equipment (NUREG-0484, Rev. 1), LRG II/1-MEB

1.14.1.84.1 Issue

The LRG II participants must justify the use of SRSS methodology for mechanical equipment in LRG II plants.

1.14.1.84.2 Response

Dynamic load combination, where applicable, is consistent with NUREG-0484, Rev. 1 guidelines for HCGS.

1.14.1.85 Loading Combinations, Design Transients, and Stress Limits, LRG I/MEB-4

1.14.1.85.1 Issue

The NRC staff asked the applicants' to consider in their NSSS fatigue analyses the cyclic loadings due to the operating basis earthquake and safety/relief valve actuation.

1.14.1.85.2 Response

The issue is addressed in Section 3.7.3.2 and Table 3.9-5a (Note 2).

1.14.1.86 Stress Corrosion Cracking of Stainless Steel, LRG I/MEB-5

1.14.1.86.1 Issue

There have been numerous occurrences of stress corrosion cracking in stainless steel components of nuclear reactors, diminishing their safety function. To assure that stainless steel components can perform commensurate with their safety function, there must be adequate controls to remedy the causes of stress corrosion cracking.

1.14.1.86.2 Response

Stress corrosion cracking is caused by a combination of oxygen in the wetting fluid, high stresses, and sensitization of the stainless steel.

Oxygen in the reactor coolant and BWR water chemistry is discussed in Section 5.2.3.

Sensitization of the stainless steel components is minimized whenever possible through the implementation of the fabrication control requirements outlined in Regulatory Guides 1.31, 1.36, and 1.44 in conjunction with Regulatory Guides 1.37, 1.38, and 1.39.

Compliance with these regulatory guides is discussed in Section 1.8. Processing controls in the fabrication of stainless steel components are further discussed in Sections 4.5.1, 4.5.2, and 5.2.3.

1.14.1.87 Pump and Valve Operability Assurance Program, LRG I/MEB-6

1.14.1.87.1 Issue

The NRC staff requested additional information regarding the applicant's analyses and testing for their pump and valve operability assurance programs.

1.14.1.87.2 Response

This issue is addressed in Section 3.9.3.2.

1.14.1.88 Bolted Connections for Supports, LRG I/MEB-7

1.14.1.88.1 Issue

Provide the allowable limits for buckling for the reactor vessel support skirt subjected to faulted conditions.

1.14.1.88.2 Response

A buckling analysis of the reactor vessel support skirt for HCGS was performed combining the effects of faulted-condition mechanical loads, thermal stress, and external pressure. This analysis showed that the support skirt has the capability to meet the faulted condition limit in the ASME B&PV Code, Section III, paragraph F-1370(c) of 0.67 times the critical buckling strength for linear supports at temperature. The buckling stress of the skirt was calculated to be 0.316 of the critical buckling strength.

The mechanical loads (axial, shear, and overturning moment) were taken from the most limiting faulted load combination. This load combination included weight and the dynamic loads due to jet reaction, annulus pressurization, and SSE.

1.14.1.89 Pump and Valve Inservice Testing Program, LRG I/MEB-8

1.14.1.89.1 Issue

Indicate compliance with 10CFR50.55a(g).

1.14.1.89.2 Response

As discussed in Section 3.9.6, inservice testing of certain safety- related pumps and valves is in accordance with 10CFR50.55a(g); and equipment lists, test schedules, methods and procedures are presented separately from the FSAR in the HCGS inservice pump and valve testing programs. Requests for relief from ASME B&PV Code, Section XI are discussed in Section 3.9.6.3.

1.14.1.90 SRV In-Situ Test Program, LRG I/MEB-9

1.14.1.90.1 Issue

Review of in-situ test program of the safety relief valve.

1.14.1.90.2 Response

HCGS participated in the BWROG program to test safety relief valves. For further details see Section 1.10, Item II.D.1. Section 3.9.2 describes seismic testing and analyses for the safety/ relief valves. Section 5.2.2 describes additional safety/relief valve inspection and test requirements.

The original SRVs at Hope Creek were the 2-Stage Target Rock SRVs. Target Rock 3-Stage SRVs have been evaluated and approved for installation at Hope Creek. The 3-Stage SRVs have been evaluated by the NSSS vendor General Electric to meet the requirements of Section 1.10, Item II.D.1 (GE Document 001N2205, PSEG VTD 432432. UFSAR Sections 3.9.2 and 5.2.2 have been updated as necessary.

1.14.1.91 CRD System Return Line Removal, LRG I/MEB-11

1.14.1.91.1 Issue

The NRC staff was concerned with the impact of the elimination of the control rod drive (CRD) return line on the performance of the CRD system.

1.14.1.91.2 Response

See response to LRG Issue No. 2, Section 1.14.1.2.

1.14.1.92 Test Program Documentation for High and Moderate Energy Piping Systems, LRG I/MEB-12

1.14.1.92.1 Issue

On some dockets the NRC staff has requested that the test program be documented for non-Class 1, 2, and 3 piping systems that carry high energy fluids outside the containment and for all Seismic Category I portions of piping systems that carry moderate energy fluids outside containment.

1.14.1.92.2 Response

This issue is adequately addressed for NSSS piping in Section 3.9.2.1 and non-NSSS piping in Section 3.9.2.2.

1.14.1.93 OBE Stress Cycles for the Mechanical Design of NSSS Equipment and Components, LRG II/3-MEB

1.14.1.93.1 Issue

The fatigue evaluation for the reactor pressure vessel and internals is based on 10 peak operating basis earthquake (OBE) cycles. However, the Standard Review Plan (SRP) requires that this evaluation include contributions from five OBEs with 10 cycles each.

1.14.1.93.2 Response

For NSSS piping, 50 cycles are postulated in accordance with the SRP criterion. For other NSSS equipment and components, ten peak OBE cycles are postulated as documented in a December 3, 1981 letter from R. Artigas (General Electric) to R.J. Bosnak (NRC). Mr. Bosnak's response, dated February 18, 1982 accepted this approach but pointed out that "Results were not provided for BWR/4 plants... (and the NRC) will require that the plant-specific results... be provided to the staff when the fatigue calculations are completed." During a subsequent MEB-SER review meeting for Limerick, the NRC staff accepted the results of a generic BWR/4 study which showed that for the most limiting BWR/4 component, the vessel feedwater nozzle, the to the cumulative fatigue usage factor contribution from 10 peak OBE cycles would be 0.006; the contribution from all other sources would be 0.067.

1.14.1.94 <u>Kuosheng Incore Instrument Tube Break, LRG II/4-MEG</u>

1.14.1.96.1 Issue

During a Kuosheng 1 shutdown, an incore instrument tube break resulted in an extended low-pressure coolant injection (LPCI), eventually causing fatigue failure of an incore instrument tube and a subsequent one-gpm leakage from the vessel.

1.14.1.94.2 Response

This situation can only occur in BWR/6 plants where the LPCI is connected to the core shroud below the top guide plate, allowing the LPCI flow to impinge directly on the upper end of the core and causing instrument tube vibration. In previous BWR designs the LPCI is connected to the shroud above the top guide plate. Hence, this issue is not applicable to the HCGS.

1.14.1.95 <u>Preservice and Inservice Inspection of Class 1, 2, and 3 Components, LRG I/MTEB-1</u>

1.14.1.95.1 Issue

Submit preservice and inservice inspection programs.

1.14.1.95.2 Response

As discussed in Section 5.2.4 and 6.2.6, the preservice and inservice inspection of Class 1, 2, and 3 components will be in accordance with the provisions of 10CFR50.55a(g).

1.14.1.96 <u>Inspectability of Welded Fluid Head Design on Main Steam Line Containment Penetration LRG II/1-MTEB</u>

1.14.1.96.1 Issue

The inspectability of welded flued head design on main steam line containment penetration should be demonstrated via the following activities:

1. Verify that the plant configuration allows adequate accessibility to the penetration to perform necessary inspections.

2. Determine if the penetration weld was ultrasonically examined during manufacturing. If so, report on examination results.

3. Determine if additional details exist on the flued head design and inspectability demonstrations performed at the Associated Pipe and Engineering facility in 1976 and 1977 and documented in General Electric Company Topical Report NEDO-23652, "Analysis on General Electric Designed Welded Flued Head Fitting at Containment Penetration Assembly and Provisions for Nondestructive Examination of Flued Head Fitting to Process Pipe Weld for BWR/6 Mark III - 218, 238, 251 Plants".

1.14.1.96.2 Response

The inspectability of the main steam containment penetration has been verified as follows:

1. The plant configuration permits adequate accessibility to the main steam line containment penetration to perform the necessary inspections. An attached anchor ring prevents access to the top of the flued head. However, GE has demonstrated the feasibility of achieving full volumetric coverage of the flued head to process pipe attachment weld when access to only the front face of the flued head is available. For Ultrasonic (UT) examination of the inaccessible inner (nearest the drywell) flued head to process pipe weldseam, refracted longitudinal wave search units were placed against the front face just above the outer weld fillet, and scanned circumferentially around the flued head. Those UT exams demonstrated strong signal amplitudes with minimum geometric reflection from the process pipe when 250 and 200 refracted 2-wave search units were used.

2. The flued head fitting to main steam line process pipe attachment weld seams were not ultrasonically examined during manufacturing. Instead the fabricator performed liquid penetrant, magnetic particle, and radiographic examinations.

   These examinations revealed no indications that required repair.

3. In July 1976, General Electric Company conducted the feasibility study of pulse echo ultrasonic testing (UT) to assure full volume coverage of the flued head attachment weld. This UT examination technique as repeated as a demonstration for utility, architect/engineer and NRC representatives during July 1976 and May 1977 at the Associated Pipe and Engineering facility in Compton, California. The results of the demonstration are documented in the draft report NEDO-23652. No additional documentation on a demonstration performed is

available.

The preservice inspection contractor for HCGS, Southwest Research Institute, intends to develop and qualify a UT examination procedure prior to performance of the examination.

1.14.1.97 Clarification and Justification of the Methods Used to Construct the Operating Pressure/Temperature Limits LRG I/MTEB-2 and MTEB-4

1.14.1.97.1 Issue

Some plants have had to take certain exceptions to Appendix G of 10CFR50 and to Appendix G of Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code. The NRC staff has requested that sufficient information be submitted to establish that the methods used to provide stress intensity values and to construct the operating pressure/temperature are equivalent to those obtained from Appendix G of Section III of the ASME B&PV Code.

1.14.1.97.2 Response

The HCGS reactor will be operated in a manner that will minimize the possibility of rapidly propagating a failure. For all phases of plant operation, the pressure/temperature limit curves were established by using the available impact test data and conservative estimates of the nil-ductility transition reference temperatures (RT_{NDT}) to perform fracture toughness calculations by the methods of Appendix G (Summer 1972 Addenda) of Section III of the ASME B&PV Code for all shell and head areas of the vessel remote from discontinuities. These calculations were based on a postulated surface flaw equal to one quarter of the material thickness. The maximum through-wall temperature difference resulting in continuous heating or cooling at 100°F per hour was considered. The safety factors applied were in accordance with Appendix G of Section III of the ASME B&PV Code, with paragraph IV.A.2.c of Appendix G of 10CFR50, and with Reference 5.3-3.

In addition, the vessel nozzle discontinuities (including the feedwater nozzle and the bottom head penetration for the control rod drives) were evaluated by adjusting the results of a BWR/6 discontinuity analysis to the HCGS reactor. The adjustments were made by increasing the minimum temperatures required by the differences in the material's RT_{NDT} values. Also, the effect of the main closure flange discontinuity was considered by adding 60°F to the flange region RT_{XDT} values whenever the pressure exceeded 20 percent of the hydrotest pressure (see Figure 5.3-1). Additions of 120°F and 160°F to the RT values for nonnuclear heatup and nuclear heating, respectively, did not yield limiting curves.

1.14.1.98 Exemptions from Appendix H To 10CFR50, LRG I/MTEB-3

1.14.1.98.1 Issue

The applicants' surveillance programs for the reactor pressure vessel (RPV) did not conform to all of the provisions of Appendix H of 10CFR50. The NRC staff asked for exceptions to be identified and justified.

1.14.1.98.2 Response

This issue is covered in Section 5A.4. The HCGS RPV was built according to the provisions of the 1968 Edition of the ASME B&PV Code, Section III, with the Winter, 1969 addenda. This was prior to the promulgation of Appendix H of 10CFR50. The HCGS surveillance program is designed to conform to the regulatory requirements applicable at the time the RPV was fabricated.

1.14.1.99 Reactor Testing and Cooldown Limits, LRG I/MTEB-4

1.14.1.99.1 Issue

Some plants have had to take certain exceptions to Appendix G of

10CFR50 and to Appendix G of Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code. The NRC staff has requested that sufficient information be submitted to establish that the methods used to provide stress intensity values and to construct the operating pressure/temperature are equivalent to those obtained from Appendix G of Section III of the ASME B&PV Code.

1.14.1.99.2 Response

See response to LRG Issue No. 97, Section 1.14.1.97.

1.14.1.100 Exposure Resulting From Actuation of Safety/Relief Valves (SRVs), LRG II/1-RAB

1.14.1.100.1 Issue

The occupational dose assessment should include projected doses during normal operation and anticipated operational occurrences. The doses to plant personnel in the Reactor Building following a Type 2 SRV isolation scram should estimate maximum doses to workers rather than the average values. Provide the assumptions used in the calculations and estimate the whole body, skin, and thyroid doses to plant personnel following a SRV discharge.

1.14.1.100.2 Response

The above issue is not applicable to HCGS since HCGS is a Mark I containment design and the SRV discharges are directed to the suppression pool where access is not permitted (design basis).

1.14.1.101 Routine Exposures Inside Containment, LRG II/2-RAB

1.14.1.101.1 Issue

High radiation levels may be expected in routinely visited areas of containment in the vicinity of major drywell shield penetrations.

Specific areas of concern are the reactor water cleanup rooms, standby liquid control areas, TIP station, CRD hydraulic control unit, and containment personnel lock. Provide maximum neutron and gamma exposure levels in these routinely visited areas.

1.14.1.101.2 Response

The reactor water cleanup rooms, standby liquid control areas, TIP Station, CRD hydraulic control unit, and the containment personnel lock are located outside the primary containment. The reactor water cleanup rooms are not located adjacent to the primary containment and frequent access is not anticipated during normal operation. Standby liquid control areas are not located adjacent to the drywell. During normal operation, controlled personnel access is possible into this area. CRD hydraulic control areas are not located adjacent to the drywell and controlled personnel access is possible into the CRD hydraulic control area. The TIP station is located adjacent to the drywell, however the TIP drive mechanism is installed in a low radiation area to allow controlled personnel access. The containment personnel lock is provided with removable shielding to reduce radiation level in adjacent containment areas.

As a design practice, all penetrations to the areas of low radiation are located and designed to reduce the possibility of streaming from high to low radiation areas or otherwise external shielding is provided.

All plant areas are categorized into radiation zones according to design basis radiation levels and anticipated personnel occupancy with consideration given to toward maintaining personnel exposure as low as reasonably achievable and within the standards of 10CFR20.

Radiation levels including any neutron contribution are given in shielding and radiation zoning drawings (Plant Drawings N-1011 through N-1016, N-1031 through N-1038, N-1041 through N-1047 and Figures 12.3-22 through 12.3-28).

1.14.1.102 <u>Controlling Radioactivity During Steam Dryer and Steam</u>

Separator Refueling Transfer, LRG II/3-RAB

1.14.1.102.1 Issue

Potentially high airborne radioactivity concentrations during refueling are expected since the steam dryer and steam separator must be transferred partially out of water. In addition to maintaining the equipment wet, other methods should be outlined to reduce the airborne radioactivity during transfers.

1.14.1.102.2 Response

In order to minimize exposure to airborne radioactivity during the refueling outage HCGS refueling procedure has considered the following. Normally the dryer is transported in air. However, if the dryer becomes highly contaminated, the reactor well and the storage pool are flooded and a submerged transfer effected. This is described in Section 9.1.4. Administrative controls, including direct health physics surveillance will be implemented to minimize personnel exposure.

1.14.1.103 Shielding of Spent Fuel Transfer Tube and Canal During Refueling, LRG II/4-RAB

1.14.1.103.1 Issue

All accessible portions of the spent fuel transfer tube and canal will be shielded during fuel transfer such that contact radiation levels are less than 100 rads per hour. All accessible portions must be clearly posted to identify potentially lethal radiation fields during fuel transfer.

1.14.1.103.2 Response

HCGS does not utilize a spent fuel transfer tube. Spent fuel transfer and storage is performed underwater in the fuel transfer canal and in the spent fuel pool. Since HCGS does not have a cattle chute shield design, administrative controls will be used to preclude access to the drywell during fuel movement. Personnel will not be allowed in the upper levels of the drywell during refueling operations where dose rates are normally higher. However, personnel may be permitted limited access to the lower levels for necessary work during refueling operations.

A portable shielded fuel transfer chute also is installed in the reactor cavity during refueling operations to provide additional shielding to upper drywell areas.

1.14.1.104 Combination of Loads, LRG II/1-SEB

1.14.1.104.1 Issue

For combining various dynamic loads, it is the NRC staff's position that the absolute sum method should be used unless actual time histories of the dynamic load occurrences are combined. If actual time histories are combined, details of the method used should be provided.

The Staff has given to each Mark III applicant its position concerning the combination of loads. The position is specific with respect to the consideration of pool swell and SRV loading but is not as clear as a load combination table listing all the permissible combinations of loads with their respective specified load factors. LRG-II plants should provide one such table for concrete containment, steel containment, concrete internal structures, and steel internal structures respectively.

In addition to the load combination requirement for the containment design, there is a fatigue analysis requirement for the liner of a concrete containment. For steel containment, the consideration of fatigue is specified in ASME Boiler and Pressure Code Section III, Division 1, Subsection NE. However, the liner of the concrete foundation mat of the steel containment should be treated as the liner of a concrete containment. Since the staff's position requires the pool liner to be designed in accordance with the ASME B&PV Code Section III, Division 1, Subsection NE, it is suggested that a generic method to consider fatigue of both the steel containment and the steel liner in the concrete containment should be adopted.

1.14.1.104.2 Response

HCGS uses absolute sum method or actual time histories for combining load in the design of structures. Load combinations are listed in Tables 3.8-2 and 3.8-3 for primary containment and component supports, respectively.

Fatigue analysis for the HCGS steel containment vessel is performed in accordance with ASME B&PV Code, Section III, Division 1, Subsection NE.

1.14.1.105 Fluid/Structure Interaction, LRG II/2-SEB

1.14.1.105.1 Issue

The dynamic forcing functions for various loads have been established mostly through testing on models which are generally more stiff than the actual structures to which the loads will be applied. By applying directly such forcing functions to actual structures in the analysis, the interactive effect between the fluid mass and the structure is neglected. Under certain conditions, this effect may be significant. It is proposed that a generic approach to study such effects should be established.

1.14.1.105.2 Response

HCGS is following NRC accepted guidelines (NUREG-0661) in the plant unique analysis of the containment structure. Fluid is included in the containment structural models to account for any fluid structure interaction effects (Reference Appendix 3B).

1.14.1.106 Loads Assessment of Fuel Assembly Components, LRG I/CPB-1

1.14.1.106.1 Issue

Appendix A to SRP 4.2 provides guidance for the analysis of Fuel Assembly Components and Acceptance Criteria for Fuel Assembly Response to externally applied forces. The applicant’s fuel assembly capability should be assessed accordingly.

1.14.1.106.2 Response

The potential for fuel lift for HCGS is negligibly small. Screening calculations performed were based on linear seismic and annulus pressurization analyses and comparisons of HCGS bounding limits (net holdown forces) to those for previously analyzed BWR/4 and small vessel BWR/5 plants. Although the fuel lift analysis is intrinsically non-linear, the negligibly small results justify the adequacy of the linear analyses.

The methodology and acceptance criteria used to evaluate fuel assembly components to externally applied forces are described in references 1 and 2. Both references contain NRC’s acceptance of the methodology for determining the dynamic response to external loading conditions.

1.14.1.106.3 Response References

1. “General Electric Standard Application for Reactor Fuel (GESTAR II),” NEDE-24011-P-A (latest approved revision).

1.14.1.107 Combined Seismic and LOCA Loads Analysis on Fuel, LRG II/2-CPB

1.14.1.107.1 Issue

Appendix A to SRP 4.2 provides guidance for the analysis of Fuel Assembly Components and Acceptance Criteria for Fuel Assembly Response to externally applied forces. The applicant’s fuel assembly capability should be assessed accordingly.

1.14.1.107.2 Response

See response to LRG Issue No. 106, Section 1.14.106.

1.14.1.108 <u>Nonconservatism in the Models For Fuel Cladding Swelling and Rupture, LRG I/CPB-2 and LRG II/1-CPB</u>

1.14.1.108.1 Issue

The procedures proposed in NUREG-0630 introduce additional conservatism in the models for fuel cladding swelling and rupture during a loss-of-coolant accident. To assure the degree of swelling and incidence of rupture are not underestimated as required by Appendix K of 10CFR50.46, supplemental calculations to the current ECCS analyses should be performed. If the swelling is underestimated, the bundle cooling may be overestimated, and the peak cladding temperature may be nonconservative.

1.14.1.108.2 Response

The HCGS unique ECCS calculations were prepared utilizing a cladding rupture and strain model contained in the SAFER/GESTR-LOCA methodology. The NRC staff found this methodology acceptable (see References in Section 1.14.108.2.1).

1.14.1.108.2.1 Reference

1. "General Electric Standard Application for Reactor Fuel (GESTAR II) (U.S. Supplement)," NEDE-24011-P-A-US (latest revision)

1.14.1.109 <u>Fuel Rod Cladding Ballooning and Rupture</u>

1.14.1.109.1 Issue

The procedures proposed in NUREG-0630 introduce additional conservatism in the models for fuel cladding swelling and rupture during a loss-of-coolant accident. To assure the degree of swelling and incidence of rupture are not underestimated as required by

Appendix K of 10CFR50.46, supplemental calculations to the current ECCS analyses should be performed. If the swelling is underestimated, the bundle cooling may be overestimated, and the peak cladding temperature may be nonconservative.

1.14.1.109.2 Response

See response to LRG Issue No. 108, Section 1.14.1.108.

1.14.1.110 High Burnup Fission Gas Release, LRG II/4-CPB

1.14.1.110.1 Issue

An NRC enhancement factor should be applied to calculated fission gas releases at burnups greater than 20,000 MWd/t because General Electric's GEGAP III model may underpredict these releases. If the release of low thermal conductivity fission gas is underestimated, the calculated gap conductance will be overestimated, and the peak cladding temperature (PCT) calculation will be nonconservative.

1.14.1.110.2 Response

Application of the NRC's enhancement factor is not necessary. The NRC staff has approved the taking of credit for the calculated PCT margin and for changes in the ECCS evaluation model to offset any operating penalties due to high burnup fission gas release (see References 1 and 2).

1.14.1.110.2.1 Response Reference

1. Letter from L. R. Rubenstein (NRC) to T. M. Novack (NRC), "General Electric ECCS Analysis at High Burnup", October 22, 1981.

2. “General Electric Standard Application for Reactor Fuel (GESTAR II) (U.S. Supplement),” NEDE-24011-P-A-US (latest approved revision).

1.14.1.111 Channel Box Deflection, LRG II/3-CPB and LRG I/CPB-3

1.14.1.111.1 Issue

General Electric report NEDO-21354 and Safety Communication (SC) 08-05 describe a channel deflection phenomena that may interfere with control rod insertion. Long term channel bow occurs when fuel channels are irradiated to high exposures and either are controlled early in life (shadow corrosion-induced bow) or are located in peripheral locations that have a gradient in fast neutron flux (fluence-gradient bow). Channel bulge results from the pressure difference between the inside of the bundle and the water gaps.

This channel deflection reduces the size of the gap available for control rod insertion.

A program to detect the onset of interference between the channel box and the control blade is required. NEDO-21354 and SC08-05 describe testing that can be used to measure the interference of the channel with the control blades. This testing should be included in the program or an alternative proposed.

1.14.1.111.2 Response

HCGS will follow the vendor guidelines to minimize the potential for and to detect the onset of interference between the channel box and the control blade.

The following guidelines will be used to minimize the potential for the interference between the channel box and the control blade:

1. Records should be kept of channel location and exposure for each operating cycle.

2. Channels should not reside in the outer row of the core for more than two operating cycles.

3. Channels that reside in the periphery (outer row) for more than one cycle should be oriented such that a different side faces the core edge for each successive peripheral cycle.

4. Channels that reside in the outer row of the core for three or more cycles should not be shuffled inward.

5. At the beginning of each fuel cycle, the combined outer row residence time for any two channels in any control rod cell should not exceed four peripheral cycles.

The following guidelines will be used to detect the onset of interference between the channel box and the control blade:

As a part of the core design process, analytic channel lifetime prediction methods are being used to assure clearance between control blades at BOC and during operations. The scram time testing at BOC required by the Technical Specifications after completion of core alterations and prior to exceeding the power level specified for the scram time surveillance in Technical

Specification 4.1.3.3.d may be used to confirm that channel-control blade interference is not present. If the control rod settles into notch 00 after the scram-time test, interference is not considered an operational issue. In addition, observations of interference are made periodically during the cycle whenever scram-time tests are conducted to meet the requirements of the Technical Specifications.

If the analytical lifetime predictions indicate specific cells are susceptible to channel-control blade interference or a cell exhibits signs of interference, settle testing will be performed following the recommendations in SC08-05. In the settle test, the time a control rod takes to settle is measured by performing a single notch withdrawal starting from notch 00, 02, 04, or 06.

The test result is acceptable if the rod settles, under its own weight, to the target (even) notch within 7 seconds. The settle time is defined from initiation of the settle indicator light to initiation of the target (even) notch position indication. This testing will give an early indication of interference between the channel box and the control blade and will prompt an investigation into the source of the friction.

This control rod settling friction test, along with the control rod movement requirement of Technical Specification Section 4.1.3.1.2.a, provides an equivalent level of safety as the test described in NEDO-21354. The settling friction test provides adequate assurance of the scram function. The amount of friction detectable by this test is approximately 250 lbs. Control rod drive (CRD) tests indicate that the CRD will tolerate a relatively large increase in driveline friction (350 lbs) while its performance still remains within Technical Specification limits. The control rod is in its most constrained, highest friction location when it is close to fully inserted (notches 00-06). The ability of the blade to settle from any of these positions demonstrates that the total driveline friction is less than the weight of the blade (250 lbs).

In the future, analytic channel lifetime prediction methods, benchmarked by periodic deflection measurements of a sample of the highest duty channels, could be used to assure clearance between control blades and channels without additional settling friction testing.

In lieu of settling friction testing, channel deflection measurements may be used to identify the amount of remaining channel lifetime for channels exceeding 36,000 MWd/ST (associated fuel bundle exposures).

The introduction of new channel boxes or control blades will not invalidate the HCGS guidelines for minimizing the potential for and the detection of interference between the channel box and the control blade unless so identified.

1.14.1.112 Water Side Corrosion of Fuel Cladding Due to Copper in the Feedwater, LRG I/CPB-4 and LRG II/5-CPB

1.14.1.112.1 Issue

Copper-bearing materials in such feedwater equipment as the main condenser tubes or the feedwater heater tubes can lead to high fuel cladding corrosion rates if the copper-ion concentrations in the feedwater are above industry guideline recommendations. Corrosion can be satisfactorily controlled with deep bed demineralizers and supplemental surveillance to determine if cladding corrosion is occurring.

1.14.1.112.2 Response

The HCGS feedwater heater tubes are made of stainless steel. The main condenser tubes are made of titanium, and the tube sheets are aluminum bronze. The condensate demineralizer system is designed to maintain adequate feedwater chemistry quality. In cases where industry guideline recommendations are not satisfied for feedwater chemistry quality parameters, an evaluation will be performed to document potential impacts and justify the new limit.

1.14.1.113 Cladding Water Side Corrosion, LRG II/5-CPB

1.14.1.113.1 Issue

Copper-bearing materials in such feedwater equipment as the main condenser tubes or the feedwater heater tubes can lead to high fuel cladding corrosion rates if the copper ion concentrations in the feedwater are above about 2 ppb. Corrosion can be satisfactorily controlled with deep bed demineralizers and supplemental surveillance to determine if cladding corrosion is occurring.

1.14.1.113.2 Response

See response to LRG Issue No. 112, Section 1.14.1.112.

1.14.1.114 Instrumentation to Detect Inadequate Core Cooling, LRG-II/6-CPB

1.14.1.114.1 Issue

As a response to TMI Action Plant Item II.F.2, the NRC staff has asked licensees to provide descriptions of any additional instrumentation for an unambiguous, easy to interpret indication of inadequate core cooling.

1.14.1.114.2 Response

The HCGS design does not include the use of in-core thermocouples or any other additional instrumentation for the detection of inadequate core cooling. PSE&G endorses the position of the BWR Owners Group that a diverse parameter used to monitor the adequacy of core cooling would not provide a significant benefit and that the existing design is adequate.

1.14.1.115 Rod Withdrawal Transient Analysis, LRG II/7-CPB

1.14.1.115.1 Issue

In the BWR/6 design, the total core power input to the rod withdrawal limiter is determined from first stage turbine readings. However, if the turbine bypass valve is open, the core power may be underestimated by as much as the bypass capacity; and restrictions on the use of the rod withdrawal limiter may be violated.

1.14.1.115.2 Response

This issue is not applicable to HCGS. In the BWR/4 design, the rod block monitor serves the functions of the rod withdrawal limiter in the BWR/6. The total core power input, used in the nulling and bypass circuits, is provided by the reference, average power range monitors rather than turbine first stage pressure. Therefore, the position of the turbine bypass valves has no effect on the operation of the rod block monitor.

1.14.1.116 Fuel Analysis for Mislocated or Misoriented Bundles, LRG II/8-CPB

1.14.1.116.1 Issue

Another misloading event that is sometimes limiting, especially for reloaded cores, is an assembly misorientation event. Since Clinton has a C lattice core, the only effect of misorientation is presumably on the R-factor for the tilted bundle. The NRC staff asked the applicants to comment on the size of this effect and its consequences.

1.14.1.116.2 Response

HCGS has a C lattice core and the misoriented bundle loading error, i.e., rotated 180°, is of minor consequences. The C lattice configuration has equal size water gaps on all four sides of the bundle, therefore the effect of re-distribution of pin power on R-factor for misoriented bundle is small. Similar to the D lattice, the bundle in a C lattice configuration would tilt axially due to the channel buttons at the top of the fuel assembly and the R-factor increases slightly for the C lattice.

The effect of a misoriented bundle on the R-factor and CPR has been analyzed for a C lattice core. The results show increases in R-factor and Δ CPR. However, the magnitude of the Δ CPR is less than that calculated for the limiting transient. Therefore the misoriented bundle event is not limiting CPR event.

Both the mislocated and misoriented bundle accidents are evaluated as AOOs, and if their results are potentially limiting from a transient evaluation standpoint, they are analyzed prior to each reload (see Appendix 15D).

1.14.1.117 Discrepancy in Void Coefficient Calculation, LRG II/9-CPB

1.14.1.117.1 Issue

Using two different calculation approaches, void worths differing by a factor of two are calculated. For example, in the Perry FSAR, data from Table 4.3-3, Reactivity and Control Fraction for Various Reactor States, gives a value of 0.074 (after subtracting 0.012 for the Doppler effects) while the result of integrating the curve shown on Figure 4.3-24 is approximately 0.03.

1.14.1.117.2 Response

This issue is not applicable to HCGS. The HCGS FSAR incorporates references to the Licensing Topical Report NEDE-24011-P-A (GESTAR II), precluding the need for the subject table and figure.

1.14.1.118 <u>Bounding Rod Worth Analysis, LRG II/10-CPB</u>

1.14.1.118.1 Issue

FSAR Section 15.4.9 "Control Rod Drop Accident" states that no bounding analysis needs to be performed for a rod worth of less than one percent ΔK. Provide the basis of this statement.

1.14.1.118.2 Response

Sensitivity studies presented in Response References 1 through 4 show large margins in peak enthalpy for rod worths below 1 percent ΔK. This margin is sufficiently large that changes in Doppler coefficients, scram curves, reactivity insertion shape, etc. for rod worths below 1 percent ΔK will not significantly reduce this margin. Therefore, if the compliance check shows the rod worth is below 1 percent ΔK, the peak enthalpy for the control rod drop accident will be well below the 280-cal/gm limit. No unique bounding analysis is needed.

1.14.1.118.2.1 Responses References

1. R.C. Stirn, et. al., "Rod Drop Accident Analysis for Large BWRs," March 1972 (NEDO-10527).

2. C.J. Paone, "Bank Position Withdrawal Sequence," September 1976 (NEDO-21231).

3. R.C. Stirn, et. al., "Rod Drop Accident Analysis for Large BWRs," July 1972 Supplement 1 (NEDO-10527).

4. R.C. Stirn, et. al, "Rod Drop Accident Analysis for Large BWRs," January 1973 Supplement 2 (NEDO-10527).

1.14.1.119 Core Thermal Hydraulic Stability Analysis, LRG II/11-CPB

1.14.1.119.1 Issue

Fuel design changes have increased the maximum decay ratio (MDR) beyond the original design criterion of 0.5 for thermal-hydraulic stability, and the NRC staff has not accepted General Electric's proposed new criterion of 1.0. The Staff has approved for operation previous core designs with MDRs as high as 0.7 for the initial cycle, but it will condition the licenses of BWR/6s (MDR = 0.98) to prohibit operation at natural circulation and to require new stability analyses be submitted and approved prior to second-cycle operation. The NRC is performing a generic study of the hydrodynamic stability characteristics of light water reactors. The results will be applied to the Staff's review and acceptance of stability analyses, criteria, and analytical methods of reactor vendors.

1.14.1.119.2 Response

The NRC staff has since completed its technical review of the generic stability issue via NRC Generic Letter 86-02. See response to LRG Issue No. 36, Section 1.14.1.36.

1.14.1.120 Seismic Qualification of Equipment, LRG I

1.14.1.120.1 Issue

1. The applicants commit to complete the reevaluation of the dynamic (seismic and applicable hydrodynamic) loads on safety-related equipment prior to fuel loading. Each of the plants either has or shall respond to NRC requests for

information on this subject in order that the Staff may complete its SQRT review for the plant.

2. The applicants commit to complete, to the extent practicable, the requalification of equipment necessary as the result of the evaluation in item 1 prior to full power operation. Replacement of equipment if required will be accomplished on a best effort basis.

1.14.1.120.2 Response

HCGS has committed to an equipment Seismic Qualification program which meets NRC requirements (Reference FSAR Section 3.10). HCGS has submitted the appropriate "long" equipment qualification forms for each of the SQRT audit components in letter, R. L. Mittl, PSE&G, to A. Schwencer, NRC, dated April 23, 1985, in fulfillment of the NRC request.

1.14.1.121 Environmental Qualification of Equipment, LRG I

1.14.1.121.1 Issue

NRC environmental qualification guidelines.

1.14.1.121.2 Response

HCGS has committed to an environmental qualification program as discussed in Section 3.11.

1.15 CONFORMANCE TO RULES ISSUED AFTER PLANT LICENSING

1.15.1 NRC Rule on Station Blackout

On July 21, 1988, the Code of Federal Regulations, Title 10, Part 50 was amended to include a new Section 50.63, "Loss of all Alternating Current Power," (Station Blackout). The Station Blackout (SBO) rule requires that each light-water cooled nuclear power plant licensed to operate must be able to withstand and recover from a SBO. An SBO is defined in 10CFR50.2 as the complete loss of alternating current (AC) electric power to the essential and non-essential switchgear busses (i.e., loss of offsite power concurrent with a turbine trip and unavailability of the onsite emergency ac power system). SBO does not include station batteries through inverters, nor does it assume a concurrent single failure or design basis accident of the affected Unit.

The NRC issued Regulator Guide (RG) 1.155 in August of 1988, to provide the industry with guidance that was acceptable for meeting the requirements of §50.63 of 10 CFR Part 50. In RG 1.155, the NRC states that NUMARC 87-00 (Reference 1) also provides guidance acceptable for meeting the requirements of 10 CFR 50.63, except when RG 1.155 takes precedence over NUMARC 87-00 as indicated in Table 1 of RG 1.155.

1.15.1.1 Conformance to NRC Rule on Station Blackout

An SBO coping analysis was performed to determine HCGS's coping duration and ability to cope with a SBO. This coping duration was based on:

a. Offsite Power Design Characteristic
b. Emergency AC Power Supply System Configuration
c. Calculated EDG Reliability; and
d. Allowed EDG Target Reliability

as described in programmatic standard HC.DE-PS.ZZ-0041, "Hope Creek Station Blackout Program."

The coping duration for HCGS was calculated as four hours in accordance with NUMARC 87-00, Section 3.0 with the exception of the frequency of Loss of Offsite Power events due to severe weather (SW) and Extremely Severe Weather (ESW). Site-specific weather data was used to determine the SW and ESW frequency as detailed in report no. NUS-5175, Rev. 1 (Reference 2).

The ability to cope with a SBO event is based on the ability to maintain "appropriate containment integrity" as defined in RG 1.155), provide adequate condensate inventory for decay heat removal, provide adequate class 1E battery capacity and compressed air capacity for the coping duration period, and evaluate equipment operability due to loss of ventilation. The ability to cope with a SBO event is described in programmatic standard HC.DE-PS.ZZ-0041, "Hope Creek Station Blackout Program."

In some instances, the GOTHIC computer program was used for room heat-up temperature calculation (due to loss of ventilation) instead of the NUMARC 87-00 method.

1.15.2 References

1. NUMARC 87-00, "Guidelines and Technical Bases for Initiatives Addressing Station Blackout at Light Water Reactors," Rev. 1, August 1991.

2. Halliburton NUS Environmental Corporation, NUS-5175, Rev. 1, "Estimated Frequency of Loss of Off-Site Power Due to Extremely Severe Weather (ESW) and Severe Weather (SW) for Salem and Hope Creek Generating Stations," March 1992.