U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-410
LICENSE NPF-69

NINE MILE POINT NUCLEAR STATION UNIT 2

UPDATED SAFETY ANALYSIS REPORT

OCTOBER 2016

REVISION 22

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CHAPTER 1

INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT

1.1 INTRODUCTION

This Final Safety Analysis Report (FSAR) was submitted by the Niagara Mohawk Power Corporation (NMPC) (Applicant) and its co-owners (Central Hudson Gas and Electric Corporation, Long Island Lighting Company, New York State Electric and Gas Corporation, and Rochester Gas and Electric Corporation) in support of the application for a Class 103 operating license for the nuclear power station designated Nine Mile Point Nuclear Station - Unit 2 (Unit 2).

The operating license was transferred to Nine Mile Point Nuclear Station, L.L.C. (NMPNS), on November 7, 2001, under License Amendment No. 100.

Unit 2 is located on a 364-ha (900-acre) site owned by NMPNS, and is situated on the southeast shore of Lake Ontario, Oswego County, NY, approximately 10 km (6.2 mi) northeast of the city of Oswego. Unit 2 and support facilities occupy about 18.2 ha (45 acres), and share the site with the existing Nine Mile Point Nuclear Station - Unit 1 (Unit 1) (Docket No. 50-220) which has been in commercial operation since 1969. The Nine Mile Point site is adjacent to the James A. FitzPatrick Nuclear Power Plant owned by Entergy Nuclear FitzPatrick, LLC; Unit 2 is located 274 m (900 ft) east of Unit 1 and about 716 m (2,350 ft) west of the James A. FitzPatrick plant.

Unit 2 employs a nuclear steam supply system (NSSS) consisting of a single-cycle, forced circulating boiling water reactor (BWR). The plant-rated core thermal power level (Figure 1.1-1) is 3,988 MWt corresponding to a gross electrical output of 1,369 MWe, and design thermal power of 4,068 MWt[1]. The thermal power used for the plant transient and loss-of-coolant accident (LOCA) analyses is 4,068 MWt. Radiological consequences for the design basis accidents (LOCA, main steam line break [MSLB], fire hazards analysis [FHA] and control rod drop accident [CRDA] use 4,067 MWt. All safety systems have been designed for a thermal power of 4,068 MWt. The NSSS supplier is General Electric Company-Nuclear Energy Operations (GE-NEO). The balance of the plant is designed and constructed by Stone & Webster Engineering Corporation (SWEC). Other plants designed by SWEC that are

[1]Unit 2 was originally licensed at 3,323 MWt, which is know as original licensed thermal power (OLTP). It was subsequently uprated by 4.3 percent of OLTP to 3,467 MWt, which is known as stretch power uprate (SPU). Unit 2 was further uprated to 3,988 MWt or 120 percent of OLTP, which is known as extended power uprate (EPU).

similar in concept are currently under review by the Nuclear Regulatory Commission (NRC). These are the Shoreham Nuclear Power Station, Brookhaven, Long Island, NY, and the River Bend Station, St. Francisville, LA.

The containment design employs the BWR Mark II concept of over-under pressure suppression with multiple downcomers connecting the reactor drywell to the water-filled pressure suppression chamber. The primary containment is a steel-lined, reinforced-concrete enclosure housing the reactor and the suppression pool.

The reactor building completely encloses the primary containment. The structure provides secondary containment when the primary containment is closed and in service, and provides primary containment when the primary containment is open, as during refueling. The reactor building houses the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment. The primary purpose of the reactor building is to minimize ground-level release of airborne radioactive material.

The outer wall of the reactor building is reinforced concrete up to the crane rail level above the refueling floor. Above the crane rail level, the superstructure is a steel frame using metal wall panels with sealed joints. Access to the building is through airlocks.

The power generation complex includes several contiguous buildings: the reactor building with two auxiliary bays, the control building, the turbine building, and the radwaste building. Other buildings, such as the security facility, are also located in the general plant area. A screenwell for the circulating and service water systems is located approximately 107 m (350 ft) northwest of the centerline of the reactor building.

Condenser cooling for Unit 2 is provided from a counterflow, natural-draft, hyperbolic, concrete cooling tower located approximately 330 m (1,000 ft) south of the centerline of the reactor building. The ultimate heat sink for emergency core cooling is Lake Ontario. Below grade and north of the screenwell building, there are two concrete tunnels that convey the service water intake, service water discharge, and cooling tower blowdown. A safety-related intake pipe is enclosed in each tunnel. The intake pipes extend from the intake shaft approximately 396 m (1,300 ft) northward under Lake Ontario to the submerged intake structures. One tunnel also contains the discharge pipe which extends approximately 550 m (1,800 ft) to the discharge diffuser.

Radionuclides are emitted to the atmosphere from two locations at Unit 2. These are the stack and the combined vent for the radwaste and reactor buildings. Liquid radwaste is stored for

decay or concentrated to a solid waste for controlled disposal at regulated storage sites.

The shielding design and plant layout are based on extensive experience of NMPC and SWEC in controlling radiological exposures to as low as reasonably achievable (ALARA) levels. Estimated radiological doses for normal operations and postulated accidents are all fractional parts of the doses listed in federal radiological guidelines for siting and operation of nuclear power plants. Environmental impacts are described in the separate Environmental Report-Operating License Stage (ER-OLS) being submitted for Unit 2.

This FSAR is written in accordance with Regulatory Guide (RG) 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants. The content of this FSAR addresses applicable regulatory guides issued up to July 1982.

The Unit 2 Preliminary Safety Analysis Report (PSAR) was submitted on June 15, 1972 (Docket No. 50-410). The NRC Safety Evaluation Report (SER) was issued on June 15, 1973, and the construction permit (CPPR-112) was issued on June 24, 1974. Environmental impacts related to the plant are discussed in the Environmental Report - Construction Permit Stage submitted on June 15, 1972. The NRC Final Environmental Statement was issued in June 1973.

The approximate schedule for Unit 2 fuel loading and commercial operation is as follows:

Fuel loading	March 1986
Commercial operation	October 1986

1.2 GENERAL PLANT DESCRIPTION

1.2.1 Principal Design Criteria

The principal architectural and engineering criteria for the design, construction, and operation of Unit 2 are summarized in this Section. There are two ways of considering principal design criteria: on a classification-by-classification basis, or on a system-by-system (system group) basis. Safety analyses generally utilize the information formatted in the classification-by-classification approach but system descriptions are more easily understood through the system-by-system method. This section uses both methods for summarizing the principal design criteria.

1.2.1.1 General Criteria

Some of the criteria are generally applicable to more than one classification or more than one system group. These general criteria are as follows:

1. Unit 2 is designed, fabricated, and erected to produce electric power in a safe and reliable manner. Unit design generally conforms with applicable codes and regulations. Exceptions are evaluated and justified. The General Design Criteria (GDC) of 10CFR50 Appendix A have been satisfied in the Unit 2 design.

2. Unit 2 is designed, fabricated, and erected to operate in such a way that the release of radioactive materials to the environment is limited to less than the limit and guideline values of applicable federal regulations pertaining to the release of radioactive materials for normal operations and abnormal events.

3. Unit 2 is designed to support a GE BWR and NSSS to produce steam for direct use in a turbine generator unit. This design incorporates features typical of many other BWR plants.

4. Certain portions of the plant are designed to withstand extreme natural phenomena such as earthquakes, flooding, or tornadoes, and unnatural phenomena such as fire, flooding from in-plant leakage, internally- or externally-generated missiles, and others.

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

6. Design margins for the nuclear safety systems and engineered safeguards are conservative.

7. Nuclear safety systems are designed to respond to abnormal operation transients to preclude fuel damage. Any fission products released to the environs via normal discharge paths for radioactive material will not exceed the limits of 10CFR50 Appendix I.

8. Nuclear safety systems and engineered safeguards are designed to assure that no damage to the reactor coolant pressure boundary (RCPB) results from internal pressures caused by abnormal operational transients or accidents.

9. Where positive, precise action is immediately required in response to accidents, such action is automatic and requires no decision or manipulation of controls by Station operations personnel.

10. Essential safety actions are carried out by safety-related equipment of sufficient redundancy and independence so that no single failure of active components can prevent required actions. Any single failure within the safety-related protection system shall not prevent proper protective action at the system level when required.

11. Provisions have been made for control of the components of nuclear safety systems and engineered safeguards from the control room.

12. Nuclear safety systems and engineered safeguards are designed to permit demonstration of their functional performance requirements.

13. Unit 2 features essential to the mitigation of accident consequences are designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed.

1.2.1.2 Power Generation Design Criteria

Principal power generation design criteria are as follows:

1. Fuel cladding is designed to retain integrity as a radioactive material barrier throughout the full operational range of the plant and any abnormal operation transient. The fuel cladding is designed to accommodate, without loss of integrity, pressures generated by fission gases released from fuel material throughout the design life of the fuel.

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

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

4. Control equipment is provided to allow the reactor to respond automatically to major or minor load changes and other abnormal operational transients, including bringing the reactor to a hot shutdown condition.

5. Reactor power level is manually controlled.

6. Control of the NSSS, including the reactor, is possible from a single location.

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

8. Fuel handling and storage facilities are designed to maintain adequate shielding, cooling, and water quality for spent fuel and to prevent inadvertent criticality.

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

1.2.1.2.1 Safety Design Criteria

1. The unit is designed, fabricated, and erected to operate so that the release of radioactive materials to the environment is significantly less than the requirements of 10CFR20 or 10CFR50.67. Those portions of the nuclear system that form part of the RCPB are designed to retain integrity as a radioactive barrier following abnormal operational transients or an accident event.

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

3. The NSSS and supporting systems are designed so that there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the nuclear system with other appropriate unit systems.

4. Gaseous, liquid, and solid waste disposal facilities are designed so the discharge of radioactive effluents

and offsite shipment of radioactive materials can be made in accordance with applicable regulations.

5. Design of the radwaste system provides means by which Unit 2 operators can be alerted when limits on the release of radioactive material are approached.

6. Sufficient indications are provided to determine that the reactor is operating within the limits of applicable regulations in any mode of unit operations.

7. Adequate radiation shielding is provided and access control patterns are established to allow a properly trained operating staff to control radiation doses to a level that is ALARA during normal operation.

8. Essential safety actions are designed to be carried out by equipment of sufficient redundance and independence that no single failure can prevent the required actions. Any single failure within the protection system shall not prevent proper action at the system level when required.

9. Provisions are made for control of the components of nuclear safety systems from the control room.

10. Nuclear safety systems are designed to demonstrate functional performance requirements.

11. The design of nuclear safety systems includes design allowances for environmental disturbances at the site such as earthquakes, floods, high winds, storms and other disturbances such as fire and flooding from leakage of fluid systems, internally- and externally-generated missiles, and others.

12. Standby electrical power sources are of sufficient capacity to power all necessary nuclear safety systems requiring electrical power. Standby ac and dc power sources are provided to remove decay heat when the offsite power supply is not available.

13. Engineered safeguards are designed to assure that no damage to the RCPB results from internal pressures caused by an accident or abnormal transient.

14. A primary containment is provided that completely encloses the reactor vessel. The primary containment uses the pressure suppression concept.

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

16. It is possible to test primary containment integrity and leak-tightness at periodic intervals.

17. A reactor building is provided that completely encloses both the primary containment and the fuel storage areas. The secondary containment includes a method for controlling release of radioactive materials from the barrier and includes a capability for filtering radioactive materials within the barrier.

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

19. The primary containment and reactor building, in conjunction with other engineered safeguards, limits radiological effects of accidents resulting in the release of radioactive material to the primary containment volume to significantly less than the requirements of 10CFR100.

20. Provisions are made for removing energy from within the primary containment to maintain the integrity of the primary containment system following accidents that release energy to the primary containment.

21. Piping that penetrates the primary containment structure and serves as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such potential for radioactive material release exists. Such isolation is effected in time to limit radiological effects to significantly less than the requirements of 10CFR50.67.

22. The emergency core cooling system (ECCS) is provided to limit fuel cladding temperature to 2,200°F as a result of a LOCA.

23. The ECCS provides for continuity of core cooling over the complete range of postulated break sizes in the RCPB.

24. The ECCS is diverse, reliable, and redundant.

25. Operation of the ECCS is initiated automatically when required, regardless of the availability of offsite power.

26. The main control room is shielded against radiation to permit 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 a cold shutdown condition by manipulating local controls and equipment available outside the main control room.

28. Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system shuts down the reactor from any normal operating condition and maintains the shutdown condition.

1.2.1.3 System-by-System Approach

The principal architectural and engineering criteria for design are summarized below on a system-by-system or system group basis. The system-by-system presentation facilitates understanding of the actual design of any one system. Only the most restrictive of any related criteria are stated for a system. Where the most restrictive criterion is classified as a power generation consideration, less restrictive safety criteria may not be stated in the system-by-system presentation. However, the actual design of a system must reflect all criteria that pertain to it.

1.2.1.3.1 Nuclear System Criteria

Principal design criteria for the reactor, ECCS, RCPB, and reactivity control systems are as follows:

1. The nuclear system is designed to support a GE BWR rated at 3,988 MWt.

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

3. Fuel cladding, in conjunction with other unit systems, is designed to retain integrity throughout any abnormal operational transient.

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

5. Heat removal systems including the ECCS and makeup water supplies are provided in sufficient capacity, redundancy, and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions from unit shutdown to design power and for any abnormal operational transien

or accident. The capacity of such systems is adequate to prevent fuel cladding damage.

6. The reactor core and reactivity control system is designed to ensure that control rod action is capable of bringing the core subcritical and maintaining it thus, even with the rod of highest reactivity worth fully withdrawn and unavailable for insertion. An alternate reactivity control system is provided should the control rods or drive system become inoperable. The alternate system is capable of shutting down the reactor and maintaining it subcritical.

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

1.2.1.3.2 Power Conversion Systems Criteria

Components of the power conversion systems are designed to perform these basic objectives:

1. Reliably produce electrical power from the steam supplied by the reactor, condense the steam into water, and return the water to the reactor as heated feedwater, with a major portion of its gaseous and particulate impurities removed.

2. Assure that any fission products or radioactivity associated with the steam and condensate during normal operation or accident conditions are safely contained within the system or are released under controlled conditions in accordance with waste disposal regulations.

1.2.1.3.3 Electrical Power Systems Design Criteria

Sufficient preferred and standby ac and dc power sources are provided to attain prompt shutdown and continued maintenance of the unit in a safe condition under all credible circumstances. Power sources are adequate to accomplish all required engineered safeguard functions under postulated design basis accident (DBA) conditions.

1.2.1.3.4 Radwaste System Design Criteria

1. Radwaste systems are designed to limit release of radioactive materials from the unit during normal operation to significantly less than the requirements

of 10CFR20, and within the guidelines of Appendix I to 10CFR50.

2. Gaseous, liquid, and solid waste disposal systems are designed so that offsite shipments will be in accordance with applicable regulations, including 10CFR20, 10CFR71, and 49CFR171 through 179, as appropriate.

3. The design provides means by which unit operations personnel can be alerted whenever operational limits on the release of radioactive material are approached.

1.2.1.3.5 Auxiliary Systems Design Criteria

1. Auxiliary systems are provided to support the NSSS and power generation system to provide for maintenance of the plant environment, in-plant radiation and airborne contamination control, compressed air supplies, sealing steam, etc.

2. Essential auxiliary systems are designed to function during accident conditions.

1.2.1.3.6 Shielding and Access Control Design Criteria

1. 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 published regulations during normal operation. Shielding design, equipment layout, and zoning have been performed to ensure radiation doses are maintained ALARA.

2. The main control room is shielded against radiation so that in conjunction with the control room air conditioning system occupancy is allowed under accident conditions.

1.2.1.3.7 Nuclear Safety Systems and Engineered Safeguards Design Criteria

Principal design criteria for nuclear safety systems and engineered safeguards are as follows:

1. These criteria correspond to 10CFR50 GDC 1 through 64 as described in Section 3.1.2.

2. Standby ac and dc power sources are designed to have sufficient capacity to power all necessary nuclear safety systems and engineered safeguards requiring electrical power.

3. Standby ac power sources are provided to allow reactor shutdown and removal of decay heat when offsite power is not available.

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

5. Backup reactor shutdown capability is provided independently of normal reactivity control provisions. This backup system has the capability to shut down the reactor from any normal or upset operating condition and subsequently to maintain the shutdown condition.

1.2.1.3.8 Process Control System Design Criteria

Principal design criteria for process control systems are listed as follows:

<u>NSSS Process Control Design Criteria</u>

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

2. Controls are provided to manually control reactor power level.

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

4. Nuclear systems 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 actuation of nuclear safety systems or engineered safeguards.

<u>Power Conversion Systems Process Control Design Criteria</u>

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

2. The turbine is capable of responding automatically to minor changes in load.

3. The feedwater system is controlled to maintain the water level in the reactor vessel at the optimum level range.

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

5. Interlocks or other automatic equipment are provided as a backup to procedural controls to avoid conditions requiring the actuation of nuclear safety systems or engineered safeguards.

<u>Electrical Power System Process Control Design Criteria</u>

1. The safety-related (Class 1E) electrical power system is designed as a three-division system, any two out of three divisions being adequate to safely shut down the unit.

2. The protection system is designed to detect and isolate faulted equipment from the system with a minimum of disturbance in the event of any fault in the system.

3. In the event of a loss of offsite power (LOOP), the protection system isolates the emergency buses from the offsite system and initiates the starting of the standby ac power sources.

4. In the event of a LOOP and LOCA, the protection system isolates the emergency buses from the offsite system and the normal electrical system, and the standby diesel generators are started and sequentially loaded by a programmed control system to energize all safety-related loads.

5. All electrically-operated breakers are controllable from the control room.

6. Metering for generators, transformers, and other essential circuits is available in the control room.

1.2.2 Site Description

1.2.2.1 Site Characteristics: Site Location and Size

The project site comprises approximately 364 ha (900 acres) and is located on the south shore of Lake Ontario in the town of Scriba, Oswego County, NY. Unit 2 shares the site with existing Unit 1; Unit 2 and support facilities occupy about 18.2 ha (45 acres) of the total site acreage. The James A. FitzPatrick plant, owned by Entergy Nuclear FitzPatrick, LLC, is located east of the project site. The centerline-to-centerline distance between Unit 2 and the FitzPatrick plant reactor is about 716 m (2,350 ft). The distance between the Unit 1 and Unit 2 reactor

centerlines is about 274 m (900 ft). The site plan is shown on Figure 1.2-1. All activities at the site are under the direct control of NMPNS[1].

1.2.2.2 Access to the Site

The protected area of the site is isolated from the surrounding area by fencing. Access to the site is controlled at the gate of the main entrance to the plant by security personnel. All other gates are kept locked[2].

1.2.2.3 Description of the Site and Environs

Most of the land immediately to the south and west of the site is pasture or inactive farmland. For the region west, south, and east of the site, the country is characterized by rolling terrain rising gently up from Lake Ontario which lies immediately to the north of the site.

Within an approximate 8-km (5-mi) radius of Unit 2, the 1980 population was 3,468. The population for this same area is projected to be 5,301 in 1990 and 7,213 in 2010. The nearest dwellings are on Lakeview Road approximately 1.6 km (1 mi) from the Station. The Ontario Bible Conference operates a summer camp on the lakefront adjacent to the western boundary of the site[3].

Oswego, which is the nearest city, is located about 10 km (6.2 mi) southwest of the site and had a 1980 population of 19,793. The nearest population center with a population in excess of 25,000 is the city of Syracuse, approximately 53 km (32.8 mi) southeast of the site. Buffalo is approximately 217 km (135 mi) west of the site. Figure 2.1-1 shows the location of the site relative to the larger cities in New York State which are within the 80-km (50-mi) radius of the site.

1.2.3 Structures and Equipment

The buildings and structures essential to the safe operation and shutdown of the plant are designed to withstand extreme environmental and abnormal loading conditions. The structures and/or portions thereof so designated are designed to provide the protection as required from tornadoes, missiles, earthquakes, pipe whip, and internal or external flooding. Additional discussions of design considerations are found in Chapter 3.

Locations and orientation of the structures are shown on Figures 1.2-1 and 1.2-2. The general arrangement of personnel access between structures is shown on Figures 1.2-3 through 1.2-5. The general arrangement of the major structures and equipment is shown on Figures 1.2-6 through 1.2-40.

The principal structures located at the site are listed below along with the brief description of the major equipment within each structure.

The primary containment structure (Figures 1.2-6 through 1.2-12) houses the reactor pressure vessel (RPV), reactor recirculation pumps and motors, drywell cooling system unit coolers, safety relief valves (SRVs), accumulators, and other equipment.

The reactor building and auxiliary bays (Figures 1.2-6 through 1.2-12) enclose the primary containment structure. These structures house the remaining portions of the NSSS, refueling and fuel storage equipment, control rod drive (CRD) hydraulic units, equipment for the reactor water cleanup system (RWCU), equipment for the standby liquid control system (SLCS), equipment for the reactor building closed loop cooling water system (RBCLCW), and other equipment.

The radwaste building (Figures 1.2-13 and 1.2-14) houses primarily the tanks and equipment associated with the liquid and solid radwaste systems.

The control building (Figures 1.2-15 and 1.2-16) houses the main control room, standby switchgear, batteries and associated instrumentation, cables, and equipment.

The diesel generator building (Figures 1.2-17 and 1.2-18) houses three standby diesel generators, diesel oil storage tanks, and associated controls and instrumentation.

The turbine building including heater bay (Figures 1.2-19 through 1.2-25) houses the turbine generator, condensers, moisture separator reheater, condensate demineralizer system, feedwater heaters, steam jet air ejectors (SJAEs), reactor feed pumps, turbine building closed loop cooling water (TBCLCW) system, and miscellaneous tanks and equipment to support the power conversion system and other related systems.

The screenwell building (Figures 1.2-26 through 1.2-28) houses the circulating water pumps and the service water pumps with associated equipment and instrumentation.

The intake and discharge tunnels and intake structures (Figures 1.2-29 and 1.2-30) are used for transporting service water to and from the lake. The intake tunnels also supply makeup water for the circulating water system.

The main stack (Figure 1.2-31) is used to provide elevated release of gases from the offgas, standby gas treatment, and other systems.

The offgas regeneration and condensate demineralizer rooms (Figures 1.2-19 through 1.2-25) house the catalytic recombiners, offgas filter, condensate demineralizer, and related equipment.

The normal switchgear building (Figures 1.2-32 and 1.2-33) houses the normal switchgear and associated equipment.

The auxiliary boiler building (Figure 1.2-34), located north of the screenwell building, houses the electric boilers and accessories to supply steam to the plant during shutdown.

The standby gas treatment building and railroad access area (Figures 1.2-35 and 1.2-36) house the standby gas treatment filters and associated equipment and allow access for spent fuel shipping and transfer to the onsite ISFSI.

The condensate storage tank building (Figure 1.2-37) houses the condensate storage tanks and associated equipment.

The natural-draft cooling tower (Figures 1.2-38 and 1.2-39) provides the normal heat sink for heat transferred to the circulating water system from the main condensers.

The auxiliary service building (Figures 1.2-7 and 1.2-8), adjacent to the reactor building, houses the heating, ventilating and air conditioning (HVAC) room and decontamination and shower facilities for personnel.

The decontamination area (Figures 1.2-19 through 1.2-21, 1.2-23, and 1.2-24), immediately south of the radwaste building, provides the facility for decontamination of large tools and equipment, and a sample room. It also houses clean steam reboilers and related equipment.

The hydrogen storage area (for hydrogen cooling of the turbine generator, Figure 1.2-40) is located west of the offgas area. The hydrogen storage bottles are mounted on concrete pads and are in a fenced area.

The cold storage building (CSB) is located within the protected area on the east side of the station security perimeter. See Figure 1.2-1.

The building is designed to provide for the storage of radioactive materials outside of the main power block. Typical usage includes the storage of radioactive materials and equipment used to support station outages and receipt inspection of new fuel.

The CSB is posted as a Radiologically-Controlled Area (RCA). Access and storage of materials in this building are controlled by site Radiation Protection procedures.

1.2.4 Nuclear Steam Supply System

The nuclear system includes a direct-cycle, forced circulation, GE BWR that produces steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear system for the warranted power condition is shown on Figure 1.1-1.

The NSSS is further discussed in Chapters 4 and 5.

1.2.4.1 Reactor Core and Control Rods

The reactor fuel and core design are described in Section 2 of Reference 5 and Section 1 of Reference 6.

Experience has shown that the control rods are not susceptible to distortion and have an average life expectancy many times the residence time of a fuel loading.

1.2.4.2 Reactor Vessel and Internals

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

The reactor vessel is designed and fabricated in accordance with applicable codes for a pressure of 1,250 psig. The nominal operating pressure in the steam space above the separators is 1,035 psia. The vessel is fabricated of low-alloy steel and is clad internally with stainless steel (except for the top head nozzles and nozzle weld zones which are unclad).

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 RPV. The steam is then directed to the turbine through the main steam lines. Each steam line has two isolation valves in series, one on either side of the primary containment barrier.

1.2.4.3 Reactor Recirculation System

The reactor recirculation system consists of two recirculation pump loops external to the RPV. These loops provide the piping path for the driving flow of water to the RPV jet pumps. Each external loop contains one high-capacity motor-driven recirculation pump, two motor-operated maintenance valves, and one hydraulically-operated flow control valve. The variable position hydraulic flow control valve operates in conjunction with a low-frequency motor generator (MG) set to control reactor power level through the effects of coolant flow rate on moderator void content.

The jet pumps are RPV internals. They 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 still allows core flooding to approximately two-thirds of the core height, the level of the inlet of the jet pumps.

1.2.4.4 Residual Heat Removal System

The 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 RPV following a LOCA to reflood the core independently of other core cooling systems.

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 and by spraying the drywell and suppression pool air spaces with suppression pool water.

1.2.4.5 Reactor Water Cleanup System

The RWCU system 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.

1.2.4.6 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. Reactor water cleanup (RWCU) system.

3. Residual heat removal (RHR) system.

4. Reactor core isolation cooling (RCIC) system.

5. Feedwater system.

6. Emergency core cooling systems (ECCS).

7. Miscellaneous systems.

Small leaks generally are detected by monitoring area temperatures, radiation levels, and drain sump fillup and pumpout rates. Large leaks are also detected by changes in reactor water

level, primary containment pressure and changes in flow rates in process lines.

1.2.5 Electrical, Instrumentation, and Control Systems

1.2.5.1 Electrical Power System

The plant electrical power system consists of the unit generator, the switchyard, and the unit auxiliary power distribution system.

The unit generator is connected directly to the generator step-up transformers and the normal Station service transformer through isolated phase bus duct. The generator step-up transformers step up the output of the unit generator from 25 kV to a nominal 345-kV transmission system voltage. The normal Station service transformer steps down the unit generator voltage from 25 to 13.8 kV and provides an onsite (ac) power source to the unit auxiliary power distribution system.

The switchyard has two separate and independent sections: the 345-kV switchyard and the 115-kV switchyard. The output of the generator step-up transformers is connected to the 345-kV switchyard which connects the unit generator to the outgoing transmission system. The 115-kV switchyard receives power from two separate offsite power sources through two physically- and electrically-independent incoming circuits. The two circuits feed two separate reserve Station service transformers and an auxiliary boiler transformer. The reserve Station service transformers step down the offsite power from 115 to 13.8 and 4.16 kV, and provide two independent offsite power sources for the unit auxiliary power distribution system. The auxiliary boiler transformer steps down the offsite power from 115 to 13.8 and 4.16 kV. Its 13.8-kV winding supplies power to the auxiliary boiler and associated equipment; the 4.16-kV tertiary winding provides a backup source for the emergency 4.16-kV buses.

The unit auxiliary power distribution system feeds all unit auxiliary loads through 13.8-kV switchgear, 4.16-kV switchgear, 600-V load centers, 600-V motor control centers, and various ac and dc distribution panels. The system is divided into nuclear nonsafety-related and nuclear safety-related systems. The nuclear nonsafety-related auxiliary power distribution system feeds all non-Class 1E unit auxiliary loads. Under normal plant operating conditions, it is energized from the normal Station service transformer. During startup and normal shutdown conditions, it is energized from offsite power sources through reserve Station service transformers. A normal 125-V dc system, consisting of batteries, battery chargers, and distribution panels, provides a reliable source of power for protection, control, and instrumentation loads and dc motors under normal and emergency conditions of the plant. A $\pm$24-V dc system provides a reliable source for the neutron monitoring system.

The nuclear safety-related auxiliary power distribution system supplies all Class 1E unit auxiliary loads. This system is divided into three independent divisions. Division I and Division II are independent redundant divisions and supply all nuclear safety-related auxiliary loads except the high-pressure core spray (HPCS) system. The HPCS system and related equipment are supplied by Division III. All three divisions are normally energized from the offsite power sources through reserve Station service transformers. The auxiliary boiler transformer can be connected manually to act as a backup source for either the Division I or Division II supply.

Each of the three divisions of the nuclear safety-related auxiliary power distribution systems has its own independent standby diesel generator. In the event of a LOCA and/or LOOP, each division is energized from its own standby diesel generator. A 125-V emergency dc power system feeds all safety-related dc protection, control, and instrumentation loads and safety-related dc motors under normal operation of the plant as well as during emergency conditions. The system is divided into three independent divisions, each consisting of its own battery, primary and backup battery chargers, switchgear, motor control centers (MCCs), and distribution panels. Each division feeds the dc loads associated with the corresponding divisions of the nuclear safety-related auxiliary power distribution system.

Chapter 8 describes the electrical power system in detail.

1.2.5.2 Nuclear System Process Control and Instrumentation

<u>Reactor Manual Control System</u>

The reactor manual control system (RMCS) provides the means by which control rods are positioned from the control room for power control. The system operates valves in each hydraulic control unit to change control rod position. One control rod can be manipulated at a time. The RMCS includes the logic that restricts abnormal control rod movement (rod block) under certain conditions as a backup to procedural controls.

<u>Recirculation Flow Control System</u>

During normal power operation, a variable position discharge valve is used to control flow. Adjusting this valve changes the coolant flow rate through the core and thereby changes the core power level.

<u>Neutron Monitoring System</u>

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 (TIP) system provides a means to calibrate the individual LPRM sensors. The NMS provides inputs to the RMCS to initiate rod blocks if preset flux limits are exceeded, and inputs to the reactor protection system (RPS) to initiate a scram if other limits are exceeded.

Refueling Interlocks

A system of interlocks that restrict 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 hoists, fuel grapple, and control rods.

Reactor Vessel Instrumentation

In addition to instrumentation for the nuclear safety systems and engineered safety features (ESF), 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.

Process Computer System

An online process computer is provided to monitor and log process variables and to make certain analytical computations. The nuclear measurement analysis and control rod worth minimizer (NUMAC RWM) prevents rod withdrawal under low-power conditions if the rod to be withdrawn is not in accordance with a preplanned pattern. The effect of the rod block is to limit the reactivity worth of the control rods by enforcing adherence to the preplanned rod pattern.

Chapter 7 describes these systems in detail.

1.2.5.3 Power Conversion Systems Process Control and Instrumentation

Pressure Regulator and Turbine Generator Control

The 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 controls can initiate rapid closure of the turbine control valves (rapid opening of the turbine bypass valves) to prevent turbine overspeed on loss of the generator electric load.

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 three-element control system (main steam flow rate, feedwater flow rate, and reactor vessel water level) is used to accomplish this function.

Chapter 10 describes the system in greater detail.

1.2.6 Radioactive Waste System

The disposal of radioactive wastes from the site is managed by waste systems designed to meet all applicable regulatory requirements, including 10CFR20, 10CFR50, 10CFR61, GDC 60, and RG 1.21.

There are three interrelated radioactive waste treatment systems: radioactive liquid waste, radioactive gaseous waste, and radioactive solid waste. These systems are described in Chapter 11.

The radioactive liquid waste (LWS) system collects and processes radioactive waste liquids generated during plant operation and refueling, either for recycle within the plant or for discharge offsite. The process operations available to treat the liquid wastes are filtration, evaporation, demineralization, and decantation. Process descriptions and flow charts illustrate the number and sequence of processing steps to be applied to each type of liquid waste.

Gaseous radwaste from the main condenser is processed through a recombiner to remove hydrogen, after which the gas is cooled, then dried. Waste gas is then passed through a charcoal bed and filter system, which holds up radioactive components and removes particulate matter before release. Contaminated drywell and building ventilation exhausts are processed by the standby gas treatment (SGTS) and ventilation systems.

The radioactive solid waste system provides holdup, packaging, and storage facilities for eventual offsite shipment and ultimate disposal of solid radioactive waste material. The process operations consist of volume reduction of radioactive wastes such as LWS evaporator concentrates, spent resins, and filter sludges. Dry radioactive wastes such as contaminated paper, clothing, and tools are compacted and packaged. After processing, the solid waste materials are stored for additional decay and then shipped offsite for appropriate disposal. Shielding, as required during

the processing and shipment of the solid wastes, is included in the planned operation of the solid waste system.

A description and flow diagram of the processing and handling sequences for the solid wastes generated onsite is provided in Chapter 11.

1.2.7 Fuel Handling and Storage Systems

1.2.7.1 New Fuel Storage

The new fuel facility is designed to prevent inadvertent criticality and load buckling of the new fuel assemblies. Both the new fuel storage vault and storage racks are designed to comply with Category I requirements.

The new fuel storage vault is designed with sufficient drainage to preclude flooding. The vault is also equipped with a monitoring system to warn of radiation level increases above normal operating conditions.

The design of the new fuel storage racks limits k_{eff} ≤0.90 in the dry condition and k_{eff} ≤0.95 in a flooded condition.

1.2.7.2 Spent Fuel Storage

The spent fuel storage racks in the spent fuel pool are designed to maintain spent fuel in a space geometry that prevents criticality in normal and abnormal conditions. The racks are capable of withstanding maximum uplift forces generated without effect on the subcritical array. The design of the spent fuel racks will limit k_{eff} ≤0.95 in normal and abnormal storage conditions. There is sufficient shielding, a cooling system, and radiation monitoring to prevent overheating and excessive personnel exposure. The spent fuel storage pool and racks are corrosion resistant, and adhere to Category I requirements.

The spent fuel is also stored at the onsite NMPNS Independent Spent Fuel Storage Installation (ISFSI) in dry casks. The Standardized NUHOMS® horizontal modular storage system for irradiated nuclear fuel is used to store the spent fuel. The Standardized NUHOMS®-61BT and -61BTH dry shielded canisters (DSC) provide for the horizontal storage of spent fuel in a DSC which is placed in a concrete horizontal storage module (HSM). The NUHOMS® system provides confinement, shielding, criticality control and passive heat removal independent of any other facility structures or components. The NUHOMS® dry cask storage system also maintains structural integrity of the fuel during storage.

The criticality control features of the Standardized NUHOMS®-61BT and/or -61BTH DSCs are designed to maintain the neutron multiplication factor k-effective less than the upper subcritical limit equal to 0.95 minus benchmarking bias and modeling bias under all conditions.

1.2.7.3 Fuel Handling System

The fuel handling equipment includes the following:

1. Fuel inspection stand.
2. Fuel preparation machine.
3. 125-ton crane.
4. Refueling platform.
5. General purpose grapple.

6. Jib cranes.
7. Other related tools for fuel and reactor servicing.

All equipment conforms to applicable codes and standards.

1.2.7.4 Spent Fuel Pool Cooling and Cleanup System

The spent fuel cooling and cleanup (SFC) system provides removal of decay heat from the stored spent fuel and maintains specified water temperature, purity, clarity, and level. This process prevents the spent fuel from overheating and the buildup of excessive radioactive materials in the cooling water, thereby minimizing radiation levels.

The system includes two heat exchangers, each of which is capable of removing the full decay heat from a normal refueling offload of spent fuel. A cross-connection to the RHR system provides additional emergency backup cooling and cooling during a full core offload.

Chapter 9 gives further details of the fuel handling and storage system.

1.2.8 Power Conversion System

Chapter 10 provides a detailed discussion of the following equipment systems.

1.2.8.1 Turbine Generator

The turbine is a 1,800-rpm tandem-compound, six-flow, single-stage reheat unit with an electrohydraulic governor control. The turbine generator has an emergency trip system for turbine overspeed. The output of the turbine generator is 1,210.9 MWe at turbine guarantee conditions with 2.0 in Hg abs backpressure and 0 percent makeup.

The generator is a direct-driven, three-phase, 60-Hz, 25,000-V, 1,800-rpm hydrogen inner-cooled, synchronous generator rated at 1,348,400 kVA at 0.90 power factor (p.f.), 0.58 short-circuit ratio at rated hydrogen pressure of 75 psig.

1.2.8.2 Main Steam System

The main steam system delivers steam from the nuclear boiler system through four 26-/28-in OD steam lines to the turbine generator, turbine bypass valves, SJAEs, offgas preheaters, steam seal evaporator, and radwaste steam reboiler.

1.2.8.3 Main Condenser

The main condenser maintains 2.0 in Hg abs when operating at reactor warranty conditions with 66.0°F circulating water inlet temperature. The condenser includes provisions for accepting

steam bypassed around the turbine generator. Deaeration of condensate is accomplished in the condenser.

1.2.8.4 Main Condenser Air Removal System

The main condenser air removal system, using air ejectors for normal operation and vacuum hogging pumps for startup, evacuates gases from the main turbine and condenser during plant startup and maintains the condenser essentially free of gases during operation. This system handles all in-leakage of noncondensable gases through the turbine seals, condensate, feedwater, and steam systems, and noncondensables that are generated in the reactor by disassociation of water.

1.2.8.5 Turbine Gland Sealing System

The turbine gland sealing system provides mildly radioactive steam to the seals of the turbine throttle valve stem glands and the turbine shaft glands. The sealing steam is supplied by a clean steam reboiler using condensate. The unit auxiliary boiler provides an auxiliary steam supply for startup and when reactor heating steam is not available. The steam packing exhauster collects and condenses the air and steam mixture, and discharges the air and other noncondensables to the plant exhaust duct to the atmosphere using a motor-driven exhauster.

1.2.8.6 Steam Bypass System and Pressure Control System

A turbine bypass system is provided which passes steam directly to the main condenser under control of the pressure regulator. Steam is bypassed to the condenser whenever the reactor steaming rate exceeds the load passed to the turbine generator. The capacity of the turbine bypass system is approximately 18.5 percent of the nuclear boiler rated steam flow. The pressure regulation system provides main turbine control valve and bypass valve flow demands to maintain a nearly constant reactor pressure during normal plant operation. It also provides demands to the recirculation system to adjust power levels by changing reactor recirculation flow rates.

1.2.8.7 Circulating Water System

The circulating water system (CWS) provides the condenser with a continuous supply of cooling water. The CWS is a pumped closed loop system utilizing an air-cooled natural-draft cooling tower as a heat sink. Six one-sixth capacity circulating water pumps are provided to pump cooling water from the cooling tower basin through the main condenser and back to the top of the cooling tower. Makeup water is provided from Lake Ontario by the service water (SWP) system.

1.2.8.8 Condensate and Feedwater Systems

The condensate and feedwater systems supply condensate from the condenser hotwell to the RPV. The condensate is pumped by the three condensate pumps through the full flow condensate demineralizer system, the intercooler of the air ejectors, and the steam-packing exhauster to the condensate booster pumps. The condensate booster pumps pump the flow through three strings consisting of two drain coolers and five stages of low-pressure heaters each. In addition, three heater drain pumps provide approximately one-third of the feedwater flow requirements. The last low-pressure heaters discharge to the suction of three parallel motor-driven reactor feedwater pumps. The discharge of the reactor feedwater pumps passes through three one-third capacity parallel heaters and into the RPV. The feedwater flow is controlled by varying the feedwater flow control valve position.

1.2.8.9 Condensate Demineralizer System

A full-flow, deep-bed condensate demineralizer (CND) system complete with regeneration facilities, instrumentation, and semiautomatic controls is designed to ensure a constant supply of high-quality water to the reactor.

1.2.9 Nuclear Safety Systems and Engineered Safety Features

Chapters 3, 4, 5, 6, 7, 9, and 10 give further details for the following equipment and systems.

1.2.9.1 Reactor Protection System

The 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 philosophy that allows appropriate protective action even if a single failure occurs.

1.2.9.2 Neutron Monitoring System

The 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 SRMs and the IRMs provide flux level indications during reactor startup and low-power operation. The LPRMs and APRMs allow assessment of local and overall flux conditions during power range operation. The TIP system provides a means to calibrate the individual LPRM sensors. The NMS provides inputs to the RMCS to initiate rod blocks if preset flux limits are exceeded, and inputs to the RPS to initiate a scram if other limits are exceeded.

1.2.9.3 Control Rod Drive System

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

1.2.9.4 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. The supports prevent a nuclear excursion as a result of a housing failure and thus protect the fuel barrier.

1.2.9.5 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 should it become detached from the CRD. This action limits the rate of reactivity insertion resulting from a rod drop accident. The limiters contain no moving parts.

1.2.9.6 Nuclear System Pressure Relief System

A pressure relief system consisting of SRVs mounted on the main steam lines is provided to prevent excessive pressure inside the nuclear system from operational transients or accidents. The SRV discharge steam is directed to the suppression pool within the primary containment.

1.2.9.7 Reactor Core Isolation Cooling System

The RCIC system provides makeup water to the RPV when the vessel is isolated. The RCIC system uses a steam-driven turbine-pump unit and automatically operates to maintain adequate water level in the RPV for events defined in Section 5.4.6.1.

1.2.9.8 Emergency Core Cooling Systems

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

<u>High Pressure Core Spray</u>

The HPCS system provides and maintains an adequate coolant inventory inside the RPV to limit fuel cladding temperatures in the event of breaks in the RCPB. The system is initiated by either high pressure in the drywell or low water level in the vessel. It operates independently of all other systems over the entire range of pressure differences from greater than normal

operating pressure to zero. The HPCS cooling decreases vessel pressure to enable the low-pressure cooling systems to function. The HPCS system pump motor is powered by an onsite diesel generator if offsite power is not available. The system may also be used as a backup for the RCIC system.

Automatic Depressurization System

The automatic depressurization system (ADS) rapidly reduces RPV pressure in a LOCA situation in which the HPCS system fails to maintain the RPV water level. The depressurization provided by the system enables the low-pressure ECCS to deliver cooling water to the RPV. 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 that a break in the RCPB has occurred and that the HPCS system is not delivering sufficient cooling water to the RPV to maintain the water level above a preselected value. Setpoints are discussed in Section 5.2.2. The ADS is not activated unless either the low-pressure core spray (LPCS) or low-pressure coolant injection (LPCI) pumps are operating. This is to ensure that adequate coolant is available to maintain reactor water level after the depressurization.

Low-Pressure Core Spray

The LPCS system consists of one independent pump and valves and piping to deliver cooling water to a spray sparger over the core. The system is actuated by either low water level in the reactor vessel or high pressure in the drywell, but water is delivered to the core only after RPV pressure is reduced. This system provides the capability to cool the fuel by spraying water into each fuel channel. The LPCS loop functioning in conjunction with the ADS or HPCS can provide sufficient fuel cladding cooling following a LOCA.

Low-Pressure Coolant Injection

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 RPV. LPCI is actuated by either low water level in the reactor vessel or high pressure in the drywell, but water is delivered to the core only after RPV pressure is reduced. LPCI operation provides the capability of core reflooding, following a LOCA, in time to maintain the fuel cladding below the prescribed temperature limit.

1.2.9.9 Containment Systems

Primary Containment

The primary containment is a Mark II design that incorporates a drywell pressure suppression system and utilizes a large reservoir of water to function as a heat sink to absorb energy.

1. Functional Design The primary containment is a steel-lined reinforced concrete structure. It consists of a conical drywell chamber above a cylindrical suppression pool chamber separated by a drywell floor. This floor contains a piping system which would direct drywell steam into the suppression chamber reservoir in the event of a LOCA.

2. Heat Removal The containment heat removal system is summarized in Section 1.2.9.14.

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.

4. Combustible Gas Control The containment combustible gas control system is summarized in Section 6.2.5.

1.2.9.10 Containment and Reactor Vessel Isolation Control System

The primary containment and RPV 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.

1.2.9.11 Main Steam Isolation Valves (MSIV)

Although all pipelines that both penetrate the primary containment and offer a potential release path for radioactive material have 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 (MSIVs). Each is closed by spring force and pneumatic force and opened by pneumatic force. These valves fulfill the following objectives:

1. Prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the RPV resulting from either a major leak from the steam piping outside the primary containment or a malfunction of the pressure control system resulting in excessive steam flow from the RPV.

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

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

1.2.9.12 Main Steam Flow Restrictors

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

1.2.9.13 Main Steam Radiation Monitoring System

The main steam radiation monitoring system (RMS) consists of four gamma radiation monitors, located externally to the main steam lines just outside the primary containment in the main steam tunnel. The monitors are designed to detect a gross release of fission products from the fuel. The main steam RMS provides control room annunciation.

1.2.9.14 Residual Heat Removal System

The RHR system is placed in operation to limit the temperature of the 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 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 service water. The coolant is then discharged back to the suppression pool, the drywell spray header, the suppression chamber spray header, or the RPV.

1.2.9.15 Ventilation Exhaust Radiation Monitoring System

Permanently-installed process and area radiation monitors provide indications and alarms on airborne radiation in the reactor building ventilation system, drywell atmosphere, fuel storage and refueling areas, and control room atmosphere. Additionally, connections are provided in the reactor building ventilation system ductwork for continuous airborne monitors (CAMs).

1.2.9.16 Standby Gas Treatment System

The SGTS processes exhaust air from various plant systems to limit the release of airborne radioactivity, maintaining offsite dose rates below the specified limits. During a DBA, the SGTS is automatically actuated. When high radiation levels are sensed in any exhaust system connected to the SGTS, it is automatically placed in operation.

The SGTS consists of two identical, parallel but physically separated air filter train assemblies. Each assembly is capable of handling the maximum design air flow rate.

1.2.9.17 Safety-Related Electrical Power Systems

A standby power supply system is provided for the operation of emergency systems and ESFs during and following the shutdown of the reactor when the preferred power supply is not available. The standby power supply system consists of three standby diesel generators. One generator is dedicated to each of the three divisions of the safety-related electric power distribution system feeding each Class 1E load group. Any two of the three standby diesel generators have sufficient capacity to start and supply all needed ESFs and emergency shutdown loads in case of a LOCA and/or LOOP. The standby diesel generator fuel oil storage tanks are sized to hold a 7-day supply of fuel oil based on the engine running continuously at full load. A LOCA and/or LOOP signal initiates start of the standby diesel generators and the generators pick up the loads in a programmed sequence. Standby diesel generators are independent and feed separate load groups through separate, physically- and electrically-isolated distribution systems.

Failure of any one unit will not jeopardize the capability of the remaining standby diesel generators to start and run the required shutdown system and ESF loads.

A 125-V emergency dc power system feeds all safety-related dc protection, control and instrumentation loads, and safety-related dc motors under normal operation of the plant as well as during emergency conditions. The system is divided into three redundant divisions, each consisting of its own battery, primary and backup battery chargers, switchgears/MCCs, and distribution panels. Each division feeds dc loads associated with corresponding divisions of the safety-related electric power distribution system. Batteries and battery chargers are redundant and feed separate load groups through separate and isolated distribution systems, and failure of any one unit will not jeopardize the capability of remaining units to feed associated loads.

1.2.9.18 Standby Liquid Control System

Although not intended to provide prompt reactor shutdown as the control rods are, the SLCS 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 not enough control rods can be inserted into the reactor core 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.

The SLCS also provides suppression pool buffering following a LOCA accompanied by significant fuel damage, preventing re-evolution of iodine from the suppression pool by maintaining the pool pH above 7.0, in support of the alternative source term (AST) methodology.

1.2.9.19 Safe Shutdown from Outside the Control Room

In the event that the control room becomes inaccessible, the reactor can be brought from power range operation to cold shutdown conditions by use of necessary controls located in the remote shutdown room.

1.2.9.20 Main Control Room Heating, Ventilating and Air Conditioning System

The main control room HVAC system provides and maintains an environment necessary for the safety and comfort of control room personnel during shutdown of the plant and in the event of a LOCA.

1.2.9.21 Redundant Reactivity Control System (RRCS)

The RRCS determines if there is an existing transient that exceeds certain RPV pressure and water level parameters and immediately activates anticipated transient without scram (ATWS) prevention equipment. If the logic has determined that a controlled shutdown is not occurring, the RRCS activates ATWS mitigation equipment.

1.2.10 Cooling Water and Auxiliary Systems

Chapter 9 provides a detailed discussion of these systems.

1.2.10.1 Reactor Building Closed Loop Cooling Water System

The RBCLCW system is a demineralized water, closed-circuit heat transfer system that consists of three 50-percent capacity pumps and heat exchangers, along with appropriate controls and instrumentation to ensure adequate cooling capacity for reactor plant auxiliary systems and components during normal plant operations. Heat removed from components by the RBCLCW system is transferred to the SWP system.

1.2.10.2 Turbine Building Closed Loop Cooling Water System

The TBCLCW system is a demineralized water, closed-circuit heat transfer system that consists of three 50-percent capacity pumps and heat exchangers, along with appropriate controls and instrumentation to ensure adequate cooling capacity for the turbine building and radwaste building auxiliary systems and components during normal plant operation. Heat removed from components by the TBCLCW system is transferred to the SWP system.

1.2.10.3 Service Water System

The SWP system provides cooling water to various essential and nonessential components throughout the plant. Essential components are serviced by two 100-percent redundant subsystems. The nonessential components will be automatically isolated upon receipt of a LOCA signal coincident with a LOOP. The service water pumps take their suction from Lake Ontario via the screenwell complex and intake tunnels. After passing through the system, the discharge is returned to the lake and to the CWS as makeup.

1.2.10.4 Ultimate Heat Sink

The ultimate heat sink (UHS) is Lake Ontario, which provides water to the intake/discharge tunnels and is available at the screenwell building for plant use.

1.2.10.5 Plant Chilled Water System

The plant chilled water system consists of two subsystems, one serving the turbine, normal switchgear, and radwaste buildings, and one serving the control building. The subsystems provide space cooling by distributing chilled water through cooling coils located in air moving units. The control building subsystem is an essential system designed to provide chilled water for cooling during all modes of plant operation. Each subsystem contains mechanical refrigeration water chillers, circulation pumps, piping valves, cooling coils, accessories, instrumentation, and controls.

1.2.10.6 Heating, Ventilating, and Air Conditioning Systems

Individual HVAC systems are provided throughout the plant to maintain indoor temperature and humidity design conditions as required for optimum performance of plant equipment and, where applicable, for human comfort.

1.2.10.7 Process Sampling

The process sampling system consists of the reactor plant, turbine plant, and radwaste sampling subsystems. These subsystems are composed of the necessary piping, valves, coolers, instrumentation, and analyzers to draw and analyze samples of various plant process streams. Representative samples are taken automatically and/or manually for on-line and laboratory analyses of pH, conductivity, suspended solids, oxygen, hydrogen, gaseous activity, fission product activity, dissolved gas concentration, and various metallic concentrations (such as copper, iron, and silica).

1.2.10.8 Condensate Makeup and Drawoff System

The condensate makeup and drawoff system consists of two storage tanks, piping, and instrumentation. It receives drawoff water from and supplies makeup water to the main condenser and fuel pool, and provides makeup of reactor coolant inventory for the RCIC and HPCS systems. Water in the condensate storage tanks (CST) is replenished from the makeup water treatment system.

1.2.10.9 Water Treatment and Makeup Water Systems

The water treatment system (WTS) uses a mobile self-contained demineralizer processing unit which is brought onsite. The system processes domestic water and delivers it to the demineralized water storage tanks.

The makeup water system (MWS) provides demineralized makeup water from the storage tanks for the power conversion system and the TBCLCW and RBCLCW systems. In addition, the MWS system satisfies various miscellaneous plant requirements for demineralized water, including the suppression pool and the spent fuel pool.

1.2.10.10 Domestic Water and Sanitary Drains and Disposal Systems

Domestic Water System

Domestic water for drinking and to satisfy the flow and pressure requirements of all installed plumbing fixtures is supplied from an existing city main. Water quality is in accordance with applicable standards promulgated by the State of New York.

Sanitary Drains and Disposal System

Raw sanitary waste from Unit 2 is directed to the Nine Mile Point Unit 1 sanitary waste treatment plant. This plant conforms to all applicable local, state, and federal discharge limitations.

1.2.10.11 Compressed Air Systems

The compressed air systems are composed of a service (SAS) and instrument air system (IAS) and a breathing air system (AAS).

Service and Instrument Air System

Three air compressors, each discharging through an aftercooler, a filter, and an air receiver into a common header, supply all the service and instrument air required by the plant. The service air is taken directly from the common header. The instrument air is passed through one of two 100-percent capacity air dryers and then through one of two 100-percent capacity air filters before delivery to the various plant instruments.

Breathing Air System

The AAS system is supplied from the instrument air common supply header through a pressure reducing station. The air is supplied to a receiver. Air from this receiver is filtered to comply with OSHA requirements for breathing air.

1.2.10.12 Auxiliary Steam System

An auxiliary steam system (ABM) furnishes a separate and independent steam supply. Process steam is generated in high-voltage, electrode boilers and distributed throughout the plant by an auxiliary steam header. Auxiliary steam is required for main turbine shaft sealing steam during startup and for the radwaste building during plant shutdown.

1.2.10.13 Standby Diesel Generator Fuel Oil Storage and Transfer System

The standby diesel generator fuel oil storage and transfer system supplies fuel oil for operation of the standby diesel generators. This system is an essential system and is capable of supplying fuel oil during all modes of plant operation, including a LOOP coincident with a LOCA.

1.2.10.14 Fire Protection System

The fire protection system consists of fire hydrants, hose stations, and automatic sprinkler and deluge systems. Where required, automatic or manually-actuated carbon dioxide (CO_2), foam, or Halon fire suppression systems are provided. Automatic fire detectors are provided in selected areas. Portable fire extinguishers and fire hose reels are located throughout the plant.

1.2.10.15 Communication Systems

The Station communication systems are designed to provide reliable communication between all essential areas of the Station and to locations remote from the Station during normal and emergency conditions and under maximum potential noise levels. This is achieved through five different communication systems as follows:

1. A dial telephone system for voice communication between selected office areas and selected locations inside and outside the Station. The dial telephone system is connected to a telephone tie system for offsite communication, including communication with local law enforcement authorities and the local fire department.

2. A portable radio communication system for communication outside the Station, in case the dial telephone system between the Station and the points outside the Station

becomes inoperable. The radios are powered by rechargeable batteries and are independent of any electrical system of the plant.

3. A page party/public address (PP/PA) communication system with five party channels and one page channel for communication between all buildings and locations within the plant, even under extremely noisy conditions. This is also used for the emergency alarm and evacuation system and is powered from an uninterruptible power supply (UPS).

4. A separate maintenance and calibration communication (M/CC) system for use in areas requiring communication for testing, instrument calibration, maintenance, and for use during construction and startup.

5. One of the channels of the M/CC system is capable of being operated as a sound-powered communication (SPC) system. This system can be used in case of a total loss of electric power to the PP/PA and M/CC systems. This system requires no plant electric power and works through M/CC system wiring.

The design of the communication systems permits routine surveillance and testing without disrupting normal communication facilities. The paging system is electrically supervised, permitting immediate corrective action to be taken if the line becomes inoperative.

1.2.10.16 Lighting Systems

The Station lighting systems are designed to provide adequate lighting in all necessary areas of the Station during both emergency and normal operating conditions. This is achieved through the following lighting subsystems:

1. Normal Station lighting system.

2. Emergency lighting system.

3. Essential lighting system.

4. Egress lighting system.

5. 8-hr battery-pack lighting system.

The normal Station lighting system provides adequate lighting in all areas of the Station under normal operating conditions. This is fed from the Station normal 600-V load centers, through the main lighting distribution panels, dry-type transformers, and subdistribution panels, except that panel 2LAR-PNL200 is normally fed from offsite power sources in a way similar to the emergency lighting system described below.

The emergency lighting system provides adequate lighting required for operating the safety-related equipment during emergency conditions in the control room, diesel generator rooms, emergency switchgear areas, and relay and computer room. This is treated as a Class 1E system except for the lighting fixtures. The lighting fixtures are seismically supported. The emergency lighting system is divided into three separate divisions corresponding to Divisions I, II, and III of the plant emergency ac distribution system and is fed from the corresponding Class 1E load centers/MCCs through the main lighting distribution panels, dry-type distribution transformers, and subdistribution panels.

In a case of a LOOP, the emergency lighting system is automatically connected to the emergency diesel generators. The emergency lighting system fixtures are constantly energized. The essential lighting system provides partial lighting for certain critical areas of the Station requiring continuous lighting, such as the control room, relay and computer room, standby diesel generator rooms, emergency switchgear rooms, service water pump room, and for passageways to and from areas where safety-related equipment is located, with the exception of those areas and passageways where 8-hr battery-pack lighting is provided to meet the requirements of 10CFR50, Appendix R. In these areas and passageways, access and egress lighting is provided by the 8-hr battery-pack lighting in the event of loss of normal lighting. The essential lighting system receives power from the Station normal UPS system and is fed through main and subdistribution panels. The essential lighting fixtures powered by the UPS system are constantly energized.

The egress lighting system provides adequate lighting for all egress signs inside the plant. This is designed as a separate system specifically for the inside building egress emergency conditions in accordance with OSHA requirements. The egress lighting system receives power from the Station normal UPS system as part of the essential lighting distribution system. The egress lighting fixtures are constantly energized.

The 8-hr battery-pack lighting provides illumination in all areas required for operation of any safe shutdown equipment and in access and egress routes thereto in case of a fire. The 8-hr battery-pack lighting also provides required illumination for access/egress to certain areas of the plant if the normal lighting in these areas is not available.

Fluorescent, incandescent, and high-pressure sodium lamps are used for Station lighting. Fluorescent lamps are used for all offices and for most of the operating areas such as the control room, relay and computer room, and emergency and normal switchgear rooms. Incandescent lamps are used in the primary containment, primary containment access hatches, main steam tunnel, new fuel storage vault, spent fuel pool filter room, and in all other areas where lighting is infrequently required.

High-pressure sodium lamps are used for all high bay lighting such as in the turbine building and reactor building general areas.

1.2.11 References

1. Nine Mile Point Nuclear Station - Unit 2, License Amendment No. 100, November 7, 2001.

2. Niagara Mohawk Power Corporation. Environmental Report (Construction Permit Stage), Nine Mile Point Nuclear Station - Unit 2, June 1972.

3. Oswego County Planning Board. Preliminary Land Use Plan, August 1976.

4. Gulf & Western Topical Report. G&W-FSD 2538, Nuclear Main Steam Isolation Valve Systems, January 1979.

5. General Electric Licensing Topical Report. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision).

6. General Electric Licensing Topical Report. General Electric Standard Application for Reactor Fuel (U.S. Supplement), NEDE-24011-P-A-US (latest approved revision).

1.3 COMPARISON TABLES

1.3.1 Comparison with Similar Facility Designs

This section highlights the principal design features of Unit 2 and compares its major features with other BWR facilities at the time of initial startup. The design of Unit 2 is based on proven technology attained during the development, design, construction, and operation of BWRs of similar types. The data, performance characteristics, and other information presented here represent the design at the time of initial startup.

Tables 1.3-1 through 1.3-7 compare Unit 2 with Washington Public Power Supply System (WPPSS) 2, Zimmer 1, and La Salle County Station 1 and 2 design characteristics for the following:

1. Nuclear steam supply system.

2. Engineered safety features.

3. Containment design.

4. Electrical power systems.

5. Radioactive waste management systems.

6. Power conversion systems.

7. Structural design.

These comparisons were considered valid at the time the initial operating license was issued.

1.3.2 Comparison of Final and Preliminary Design Information

Significant changes in procedures or materials used in the design of Unit 2 since the Unit 2 PSAR are listed in Table 1.3-8 for NSSS and Table 1.3-9 for the balance of plant. Each change is cross-referenced to the primary FSAR section that discusses the item or system. Each of these changes was reviewed and approved in accordance with administrative procedures and either it does not represent a change to the principal architectural and engineering criteria for the design, or the NRC has been notified previously of the change.

1.3.3 Reference

1. General Electric Licensing Topical Report. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision).

TABLE 1.3-1
(Sheet 1 of 3)

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
THERMAL AND HYDRAULIC DESIGN (Section 4.4)				
Rated power, MWt	3,323	3,323	2,436	3,293
Design power, MWt (ECCS design basis)	3,463	3,468	2,550	3,434
Steam flow rate, millions lb/hr	14.263	14.295	10.477	14.166
Core coolant flow rate, millions lb/hr	108.5	108.5	78.5	106.5
Feedwater flow rate, millions lb/hr	14.564	14.256	10.477	14.127
System pressure, nominal in steam dome, psia	1,020	1,020	1,020	1,020
Average power density, kW/l	49.15	49.15	50.51	50.0
Minimum critical power flux ratio (MCPR)	1.24	1.24	1.24	1.28
Coolant enthalpy at core inlet, Btu/lb	527.5	527.6	527.4	527.1
Core max exit voids within assemblies	76.2	79	75	76
Core average exit quality, % steam	13.10	13.5	13.2	13.2
Feedwater temperature, °F	420	420	420	420
Design Power Peaking Factor				
Maximum relative assembly power	1.40	1.40	1.40	1.40
Axial peaking factor	1.40	1.4	1.4	1.40
Nuclear Design (First Core)				
See [4].				
CORE MECHANICAL DESIGN (Sections 4.2 and 7.6)				
Fuel Assembly				
See [4].				
Fuel Rods				
See [4].				
Fuel Pellets				
See [4].				
Fuel Channel				
See [4].				

TABLE 1.3-1
(Sheet 2 of 3)

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Core Assembly				
See [4].				
Reactor Control System				
Method of varying reactor power	Movable control rods; variable forced coolant flow			
No. movable control rods	185	185	137	185
Type of control rod drives	Bottom entry; locking piston			
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	B_4C granules compacted in SS tubes			
Type of temporary reactivity control for initial core	Burnable poison; gadolinia-urania fuel rods			
In-core Neutron Instrumentation				
Local power range monitors (LPRM)				
Total LPRM detectors	172	172	124	172
No. of in-core LPRM penetrations	43	43	31	43
No. of LPRM detectors per penetration	4	4	4	4
Range	Approximately 1% power to 125% power			
Average power range monitors (APRM)				
No. detectors	4[1]	6[1]	6[1]	6[1]
Range	Approximately 1% power to 125% power			
Source range monitors (SRM)				
No. detectors	4	4	4	4
Range	Source to 0.001% power			
Intermediate range monitors (IRM)				
No. detectors	8	8	8	8
Range	0.001-10% power	0.001-10% power	0.001-10% power	0.001-10% Power
No. flux-mapping neutron detectors	5	5	4	5
No. and type of in-core neutron sources	7Sb-Be	7Sb-Be	5Sb-Be	7Sb-Be

TABLE 1.3-1
(Sheet 3 of 3)

COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
REACTOR VESSEL DESIGN (Section 5.3)				
Material	Low-alloy steel/ stainless clad	Carbon steel/ stainless clad	Low-alloy steel/ stainless	Carbon steel/ stainless clad
Design pressure, psig	1,250	1,250	1,250	1,250
Design temperature, °F	575	575	575	575
Inside diameter, ft-in	20-11	20-11	18-2	20-11
Inside height, ft-in	72-5	72-11	69-10	72-11
Minimum base metal thickness (cylindrical section), in	6.1875	6.75	5.375	6.75
Minimum cladding thickness, in	1/8	1/8	1/8	1/8
REACTOR COOLANT RECIRCULATION DESIGN (Sections 5.1, 5.2, and 5.4)				
No. recirculation loops	2	2	2	2
Design pressure				
Inlet leg, psig	1,250	1,250	1,250	1,250
Outlet leg, psig	1,650[2] 1,550[3]	1,650[2] 1,550[3]	1,675[2] 1,575[3]	1,650[2] 1,550[3]
Design temperature, °F	575	575	575	575
Pipe diameter, in	24	24	20	24
Pipe material, AISI	316K	304/316	304/316	304/316
Recirculation pump flow rate, gpm	47,200	47,250	32,500	47,250
No. jet pumps in reactor	20	20	20	20
MAIN STEAM LINES (Section 5.4)				
No. steam lines	4	4	4	4
Design pressure, psig	1,250	1,250	1,250	1,250
Design temp, °F	575	575	575	575
Pipe diameter, in	26/28	26	24	26
Pipe material	Carbon steel	Carbon steel	Carbon steel	Carbon steel

[1] Channels of monitors from LPRM detectors.
[2] Pump and discharge piping to and including the discharge block valve.
[3] Discharge piping from discharge block valve to vessel.
[4] General Electric Licensing Report. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision).

TABLE 1.3-2
(Sheet 1 of 2)

COMPARISON OF ENGINEERED SAFETY FEATURES
DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
EMERGENCY CORE COOLING SYSTEMS (Systems sized on design power) (Section 6.3)				
Low-Pressure Core Spray System				
No. loops	1	1	1	1
Flow rate, gpm	6,350 @ 128 psid	6,250 @ 122 psid	4,625 @ 119 psid	6,250 @ 122 psid
High-Pressure Core Spray System				
No. loops	1	1	1	1
Flow rate, gpm	1,550 @ 1,130 psid 6,350 @ 200 psid	1,650 @ 1,110 psid 6,250 @ 200 psid	1,330 @ 1,110 psid 4,725 @ 200 psid	1,650 @ 1,110 psid 6,250 @ 200 psid
Automatic Depressurization System				
No. systems	1	1	1	1
No. relief valves	7	7	6	7
Low Pressure Coolant Injection[1]				
No. LPCI systems	1	1	1	1
No. pumps	3	3	3	3
Flow rate, gpm/pump	7,450 @ 26 psid	7,450 @ 20 psid	5,050 @ 20 psid	7,067 @ 20 psid
AUXILIARY SYSTEMS				
Residual Heat Removal System (Section 5.4.7)				
No. loops	2	2	2	3
No. pumps	2	2	2	3
Flow rate, gpm/pump[2]	7,450	7,450	5,050	7,450
Duty, millions Btu/hr/heat exchanger[3]	41.6	41.6	30.8	46.6
No. heat exchangers	2	2	2	2
Primary containment cooling mode flow rate, gpm[4]	7,450	7,450	5,050	8,400

TABLE 1.3-2
(Sheet 2 of 2)

COMPARISON OF ENGINEERED SAFETY FEATURES DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Service Water System (Section 9.2.1)				
Flow rate, gpm/RHR heat exchanger	7,400	7,400	5,000	7,400
No. pumps	6	4	4[4]	4
Reactor Core Isolation Cooling System (Section 5.4.6)				
Flow rate, gpm	600 @ 1,173 psia reactor pressure	600 @ 1,120 psid	400 @ 1,120 psid	600 @ 1,120 psia reactor pressure
Fuel Pool Cooling and Cleanup System (Section 9.1.3)				
Capacity, millions Btu/hr	15.0	7.6	6.9	8.0
Standby Gas Treatment System (Section 6.5.1)				
Charcoal bed design, lb charcoal	2 independent trains 1,360 lb/train total 2,720 lb total	2 trains	2 trains, 2,000 lb/train 4,000 lb/train	2 independent trains, 3,700 lb/train 7,400 total lb
Design efficiencies, %				
Elemental iodine	99.0	99.0	99.0	90.0
Organic iodine	99.0	99.0	99.0	90.0
0.3u particles	99.97	99.97	99.0	99.97
System flow, cfm	4,000[5] scfm/train	4,000 scfm/train	2,300 scfm/train	4,000 scfm/train

(1) A mode of residual heat removal system.
(2) Capacity during reactor flooding made with two or three pumps running.
(3) Heat exchanger duty at 20 hr following reactor shutdown.
(4) Includes HPCS service water pumps.
(5) Nominal system flow rate.

TABLE 1.3-3
(Sheet 1 of 2)

COMPARISON OF CONTAINMENT DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Primary Containment[1] (Section 3.8)				
Type	Over & underpressure suppression Mark II	Over & underpressure suppression Mark II	Over & underpressure suppression Mark II	Over & underpressure suppression Mark II
Construction	Reinforced concrete steel liner	Steel freestanding	Concrete prestressed steel liner	Concrete post-tensioned steel liner
Drywell	Frustum of cone, upper portion	Frustum of cone, upper portion	Frustum of cone, upper portion	Frustum of cone, upper portion
Pressure suppression chamber	Cylindrical lower portion	Cylindrical lower portion with elliptical bottom	Cylindrical lower portion	Cylindrical lower portion
Pressure suppression chamber - internal design pressure, psig	45	45	45	45
Pressure suppression chamber - external design pressure, psig	4.7	2	2	5
Drywell-internal design pressure, psig	45	45	45	45
Drywell-external design pressure, psig	4.7	2	2	5
Drywell free volume, ft^3	303,418	200,540[2]	180,000[3]	221,518
Pressure suppression chamber free volume (min), ft^3	192,028	144,184[4]	93,000	166,400
Pressure suppression pool water volume, ft^3	154,794[5]	112,197	102,120	109,096
Submergence of vent pipe below suppression pool surface, ft	9.5 min 11.0 max	11.67 min 12.00 max	10	12
Design environmental temperature of drywell, °F	340	340	340	340
Design environmental temperature of pressure suppression chamber, °F	270	275	275	275

TABLE 1.3-3
(Sheet 2 of 2)

COMPARISON OF CONTAINMENT DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Downcomer vent pipe pressure loss factor	1.37[6]	1.9	2.17	1.9
Break area/total vent area	0.0108	0.0105	0.008	0.0105
Calculated maximum pressure after blowdown to drywell, psig	39.7	34.7	40.4	34
Calculated maximum pressure in suppression chamber, psig	34.0	28.0	35.6	28
Calculated maximum initial pressure suppression pool temperature rise, °F	50	35	35	50
Leakage rate, % free volume/day at 45 psig and 340°F	1.1 @ 200°F	0.5 @ 200°F	0.635	0.5
Reactor Building (Sections 3.8.4, 6.2)				
Type	Controlled leakage, elevated release[7]	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release
Construction				
Lower levels	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Upper levels	Steel superstructure and siding	Steel superstructure and siding	Steel superstructure and siding	Steel superstructure and siding
Roof	Steel decking	Steel decking	Steel decking	Steel decking
Internal design pressure, psig	0.25	0.25	0.25	0.25
Design in-leakage rate, % free volume/day at 0.25 in H_2O	100	100	100	100

(1) Where applicable, containment parameters are based on design power.
(2) Maximum water in suppression pool.
(3) Includes the vent volume.
(4) Maximum value.
(5) At high water level.
(6) Includes entrance and pipe friction.
(7) For accident conditions.

TABLE 1.3-4
(Sheet 1 of 1)

COMPARISON OF ELECTRICAL POWER SYSTEM DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Offsite Power System (Section 8.2)				
Outgoing lines (No.-rating)	1-345-kV	1-500-kV	3-345-kV	2-345-kV (per unit)
Incoming lines (No.-rating)	2-115-kV	1-230-kV 1-115-kV	1-69-kV 1-345-kV	2-345-kV (per unit)
Onsite ac Power System (Section 8.3.1)				
Normal station service transformers	1	2	1 (unit auxiliary)	1 per unit
Reserve station service transformers	3[1]	2	2	1 (system aux)
Standby diesel generators	3[2]	3[2]	3	3[3]
4,160-V ESF buses	3[2]	3[2]	3	3
ESF buses	3-600-V[2]	3-480-V[2]	5-480-V	4-480-V
dc Power Supply (Section 8.3.2)				
Batteries (No.-volts)	6-125-V[4] 4 ± 24-V	4-24-V 5-125-V[4] 1-250-V	3-125-V 1-250-V	3-125-V 1-250-V
Buses (No.-volts)	6-125-V[4] 2 ± 24-V	2-24-V 5-125-V[4] 1-250-V	3-125-V 1-250-V	3-125-V 1-250-V

(1) Includes one auxiliary boiler transformer.
(2) Includes a HPCS diesel generator.
(3) Five total for 2 units. One serves either unit.
(4) HPCS battery and bus included.

TABLE 1.3-5
(Sheet 1 of 2)

COMPARISON OF RADIOACTIVE WASTE MANAGEMENT DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Gaseous Radwaste (Section 11.3)				
Design basis, noble gases, uci/sec	100,000 after 30 min decay	100,000 after 30 min decay	100,000 after 30 min decay	100,000 after 30 min decay
Process treatment	Recombiner ambient charcoal	Low temperature charcoal	Chilled charcoal	Recombiner ambient charcoal
No. beds	8	8	5	8
Design condenser in-leakage, cfm	30	30	12.5	21
Release point, height aboveground, ft	430 (stack) 187 (vent)	230	172	370
Liquid Radwaste* (Section 11.2)				
Treatment of:				
Floor drains	F or E, F, D returned to condensate storage, concentrates to radwaste solidification	F, D returned to condensate storage	F, E returned to condensate storage	E, D returned to condensate storage
Equipment drains	F, D returned to condensate storage	F, D returned to condensate storage	F, D returned to condensate storage	F, D returned to condensate storage
Chemical waste	E, F, D returned to condensate storage, concentrates to radwaste solidification	N, E, D returned to condensate storage	E, D concentrates to solid radwaste, distillate recycled	E, D concentrates to solid radwaste, distillate recycled

TABLE 1.3-5
(Sheet 2 of 2)

COMPARISON OF RADIOACTIVE WASTE MANAGEMENT DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Liquid Radwaste (Section 11.2)				
Laundry waste	*	F, Chemical addition F, E, sent to circulating water discharge	R, discharged	R, discharged

*   Laundry will be processed offsite at Nine Mile Point Unit 1.

KEY:
D = Demineralizer
E = Evaporator or concentrator
F = Filter
N = Neutralized
R = Reverse osmosis

TABLE 1.3-6
(Sheet 1 of 1

COMPARISON OF POWER CONVERSION SYSTEM DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer* Unit 1	LaSalle Units 1, 2
Design power, MWt	3,463	3,468	2,550	3,434
Design power, MWe, gross	1,202	1,205	883	1,122
Generator speed, RPM	1,800	1,800	1,800	1,800
Design steam flow, lb/hr	14.3×10^6	15.0×10^6	11.0×10^6	14.2×10^6
Turbine inlet pressure, psia	965	970	965	965
Turbine Bypass System (Section 10.4.4)				
Capacity, percent of turbine design steam flow	25	25	25	25
Main Condenser (Section 10.4.1)				
Heat removal capacity, Btu/hr	$7,830 \times 10^6$	$7,702 \times 10^6$	$7,053 \times 10^6$	$7,609 \times 10^6$
Circulating Water System (Section 10.4.5)				
No. Pumps	6	8	3	3
Flow rate, gpm/pump	105,000	82,000	150,000	210,000
Condensate and Feedwater Systems (Section 10.4.7)				
Design flow rate, lb/hr	14.917×10^6	14.260×10^6	10.971×10^6	14.127×10^6
No. condensate pumps	3 running	3 running	3	3 plus 1 spare
No. condensate booster pumps	3 running	3 running	3	3 plus 1 spare
No. feedwater pumps	2 running 1 standby	2 running	2	3
Condensate pump drive	ac power	ac power	ac power	ac power
Condensate booster pump drive	ac power	ac power	ac power	ac power
Feedwater pump drive	ac power	Turbine	Turbine	Turbine 2 Motor 1

* Indicates parameters at rated power.

TABLE 1.3-7
(Sheet 1 of 1)

COMPARISON OF STRUCTURAL DESIGN CHARACTERISTICS (HISTORICAL)

	Nine Mile Point Unit 2	WPPSS Unit 2	Zimmer Unit 1	LaSalle Units 1, 2
Elevated Release Point (Section 11.3.3)				
Type	Stack, vent	Vent	Vent	Vent
Construction	Stack - reinforced concrete Vent - steel	Steel	Steel	Steel
Height (aboveground), ft	430 (stack) 187 (vent)	200	172	370
Seismic Design (Section 3.7)				
Operating basis earthquake				
Horizontal, g	0.075	0.125	0.10	0.10
Vertical, g	0.075		0.07	0.07
Safe shutdown earthquake				
Horizontal, g	0.15	0.250	0.20	0.20
Vertical, g	0.15		0.14	0.14
Wind Design (Section 3.3)				
Maximum sustained, mph	90	100	90	90
Tornado				
Rotational, mph	290	300	300	300
Translational, mph	70	60	60	60
Total, mph	360	360	360	360

TABLE 1.3-8
(Sheet 1 of 2)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE NSSS SCOPE OF SUPPLY (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Control rod drive position	Changed to 11 wire probe and solid state.	Improved reliability and increased frequency of checking actual rod position.	7.7.1
Recirculation pump and motor	The flow rate and horsepower required have been reduced; voltage has changed from 4,160 V to 13,200 V.	Detailed system design.	5.4
Recirculation flow measurement	The recirculation flow measurement design was changed from a flow element to an elbow-tap type.	To improve flow measurement accuracy.	5.4
Recirculation system	The pressure interlock for RHR injection was changed.	IEEE-279 requirements.	7.3.1, 7.1
Feedwater and recirculation nozzle safe ends and thermal sleeves	Material/design change. Piping changed to type 316K from type 304.	Mitigate IGSCC.	5.3
Nuclear fuel	The number of fuel pins in each fuel bundle has been changed from 7x7 to 8x8.	Improved fuel performance by increasing safety margins.	4.2
Nuclear boiler	a. A turbine building high temperature trip for MSIVs was added. b. Delete REVAB system.	Improve leak detection capability. GE Mark II suppression pool dynamics test program showed REVAB undesirable.	7.3 5.2, 5.4, 8.3.1
Main steam line isolation	A main condenser low vacuum initiation of the main steam line isolation was added.	NRC requirement.	7.3.1
Main steam line drain system	A main steam line drain system was improved.	Prevent accumulation of condensate in an idle line outboard of MSIV.	5.1
Feedwater sparger	The thermal sleeve was changed to provide welded design of sparger to nozzle.	To eliminate vibration and cracking.	5.3
RCIC steam supply	A warmup bypass line and valve were added.	Permits pressurizing and prewarming of the steam supply line downstream to the turbine during reactor vessel heatup.	5.4
Control rod drive system	Alternate rod injection and scram discharge volume modifications were implemented.	To reduce potential for failure to scram.	4.6.1

TABLE 1.3-8
(Sheet 2 of 2)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE NSSS SCOPE OF SUPPLY (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
RCIC vacuum breaker system	A vacuum breaker system was added to the RCIC turbine exhaust line into the suppression pool.	To prevent backup of water in the pipe and consequential high dynamic pipe loads and reactions.	5.4
Automatic depressurization system (ADS)	The interlocks on the ADS were revised.	To meet IEEE-279 requirements.	7.3.1
RPV stabilizer support	The RPV stabilizer's configuration was changed by adding a top plate.	Provides a better seismic and alignment capability.	5.3
Level instrumentation	The RPV level instrumentation was revised to eliminate Yarway columns and replace them with a conventional condensing chamber type; also, separation and redundancy features were added.	Improve ECCS separation in accordance with IEEE-279 and improve reliability.	7.3.1
Leak detection system	The leak detection system was revised to upgrade the capability and incorporate the requirements of IEEE-279.	To meet IEEE-279 requirements.	7.1
Reactor vibration monitoring	A confirmatory vibration monitoring test was added.	NRC requirement.	14.2
Redundant reactivity control system (RRCS)	Added RRCS to mitigate ATWS events.	To comply with NRC ruling on ATWS.	7.6, 9.3.5, 15.8

TABLE 1.3-9
(Sheet 1 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Reactor building	Addition of auxiliary bays.	Provide room to allow segregation of ECCS.	6.2.3, 3.2.1, 3.8.4
Summary description of structures	Additional buildings included in the unit.	Auxiliary bays, railroad access lock, condensate storage tank building, and demineralized water and waste neutralizer tank storage building added.	1.2, 3.2.1
Primary containment cooling	a. Power electric motor components through normal 4-kV switchgear.	Containment cooling is not a nuclear safety-related system.	8.3
	b. Revised arrangement and number of unit coolers.	Improve air distribution based on operating experience.	9.4.9
Standby gas treatment system (SGTS)	Add ASME Class 2 isolation valve between containment purge and SGTS.	To isolate containment purge (Class 4 outside containment) from Class 2 SGTS.	6.5.1
Reactor building ventilation system	a. Locate supply fans in SGT building.	Provides a more efficient isolation of the reactor building.	9.4.2
	b. Normal exhaust system to consist of two sets of two fans.	Improve system design for better air movement and optimum fan performance.	9.4.2
	c. Change from valves to zero-leakage dampers.	Reduce seismic load and closure time and compact valve design.	9.4.2
	d. Eliminate mixing box.	Credit taken for turbulent mixing during emergency operation.	9.4.2
Primary containment ventilation	All containment purge air is passed through the SGTS and vented out the stack.	To enhance safety of plant ventilation design.	6.5.1
High-density spent fuel storage	Changed spent fuel rack configuration to high-density storage design.	To increase onsite storage capacity of spent fuel.	9.1
Primary shield wall	Additional provisions added to supplement the commitment to use AISC Steel Construction Manual welding requirements.	AISC standards do not account for certain weld configurations necessary to achieve proper erection, hence additional standards used for those weld configurations.	3.8.3

TABLE 1.3-9
(Sheet 2 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Primary containment liner	Referenced ASME Code and construction for design of liner also added changes in material selection.	To agree with specification requirements for incorporation of design improvements.	3.8.1
Primary containment drywell floor seal	Eliminated flexible floor seal and revised floor connection to containment wall and reactor pedestal.	Rigid design selected in order to improve maintainability and reliability and to eliminate testing of flexible seal.	6.2.1, 3.8.3
Primary containment	Changed shape of primary containment to two conical frustums.		3.8.1
Downcomer piping and drywell floor	Drywell floor thickness increased and sloped cross section incorporated. Downcomers extended. Downcomer anchor design altered to two support plates anchored onto top and bottom of drywell slab and welded to downcomers at each face. Replaces two welded seal rings.	Slab thickness increased for insulation, slope added to improve floor drainage. Downcomer extension maintains required clearance. Anchor redesign accounts for insulation slab and higher suppression pool hydrodynamic loads.	3.8.3
Drywell floor design criteria	Drywell floor designed for two independent cases; for 10 psid upward and 25 psid downward loads.	To agree more accurately with calculated conditions.	3.8.3
Leakage detection - drywell air cooler drains	Flowmeters on drains to measure leakage condensation on individual air coolers eliminated. Gaseous activity monitors added.	Concern for reliability of flowmeters mounted in the wetwell due to environmental conditions. Questionable operability and accuracy of drywell-located meter(s).	5.2.5
MSIV leakage control system	Deleted system.	System not required.	1.8, 6.2.3.2.3, 15.6.5
Equipment and floor drainage	Route drywell equipment drainage and low conductivity secondary containment drainage to radwaste system.	Drain line to condenser forms constant air leak. Resolve by routing to radwaste system.	9.3.3
Containment influent isolation valves	Change from motor-operated stop check to motor-operated gate valve farthest from containment.	Commercial availability of valves that meet design criteria.	6.2.4
Fire protection - water system	a. Allow tie valve of one of two interplant connection lines to be operated by remote control at Unit 1 control room.	Enhance fire protection at both plants on site. Selective interconnection by either plant to allow pumps to be used for pressure maintenance and fire fighting.	9.5.1

TABLE 1.3-9
(Sheet 3 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Fire protection - water system (cont'd.)	b. Upgrade fire protection water system pipe support hangers to seismic Category I in safety-related areas and in the vicinity of safety-related equipment.	Compliance with NRC Branch Technical Position (BTP) APCSB 9.5-1.	9.5.1, 3.9.3, 3.7.3
Recombiner system	Upgrade from Safety Class 3 to Safety Class 2.	Compliance with RG 1.7 and 1.26.	6.2.5
Circulating water system	Change from once-through lake water system to closed loop with natural-draft cooling tower.	EPA Effluent Guidelines*, which became effective after the last PSAR supplement, subjected the approval of once-through condenser cooling to a time-consuming development, review, and approval of a demonstration that no harm will occur to the aquatic community of the receiving water body. Based on scheduling impacts, close cycle cooling was incorporated to conform to best technology economically available as required by these guidelines.	10.4.5
Service water system	Number of pumps changed from 4 to 6 and size of pumps changed from 8,000 gpm and 450 hp to 10,000 gpm and 600 hp.	Addition of new heat loads required increase in system capacity.	9.2.1
Main steam line	Standards for fabrication, inspection, and quality assurance revised to include turbine stop valves, main turbine bypass lines to and including bypass valves, and main branch lines of 2 1/2-in diameter or larger to and including the first valve on each branch.	Conformance with RG 1.29.	5.2.1, 5.4.9
Pipe break criteria	Revised criteria for pipe break location, orientation, dynamic force pipe whip.	Requirements of RG 1.46 and report Pipe Rupture Criteria for NMP2.	3.6
Structural design criteria - seismic	a. Revised criteria for accelerations in analysis for OBE and SSE.	Conformance with RG 1.60 and 1.61.	3.7.1
	b. Added fixed-base to models of seismic Category I structures.	Foundation media of all major seismic Category I structures are founded on rock. Allows use of fixed base for dynamic analysis.	3.7.1
	c. Seismic loading will include the effects of one vertical and two horizontal response accelerations simultaneously.	NRC required this in Safety Evaluation Report (SER).	3.7.2

TABLE 1.3-9
(Sheet 4 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Structural design criteria	a. Change tornado model to adopt characteristics given in RG 1.76.	Compliance with RG 1.76.	3.3.2
	b. Add the criteria to design safety-related structures for time-dependent site foundation rock movement.	Conformance with the geologic criteria developed by Dames & Moore, geologic consultants for the site.	3.7.1, 3.7.2
Primary containment load analysis	Reduced amount of restraint material for piping and adopt requirements of ASME III-1974 NB-3225.	Reduce cost of restraint.	3.6
Reinforcing steel-splices	a. Change procedure for visual inspection of Cadweld splices.	Apply sampling inspection criteria in place of 100-percent inspection.	1.8.1.10
	b. Add DYWIDAG threadbar splices.	Provides alternate to other rebar splicing systems; adds flexibility to construction.	3.8.4
Equipment classifications - gaseous radwaste	Components reclassified as Quality Group D.	Site boundary accident dose calculations indicate that system meets Group D criteria.	3.2.2, 11.3.3
Quality assurance program	Revised engineer's QA program to adopt SWEC Standard Quality Assurance Program (SWSQAP).	To use improved QA program derived from SWEC Topical Report SWSQAP 1-74 Revision dated 8/1/75.	17.1; Table 1.8-1, RG 1.28, 1.39, 1.74, 1.88, and 1.144
Internal containment coatings	Change QA requirements from conformance with proposed ANSI Standard N101.5.7 to ANSI N101.4, RG 1.54, and Chapter 10 of ANSI N512-74.	To comply with new standards and regulatory guide.	17.1; Table 1.8-1, RG 1.54
Materials for construction - reinforcing steel	a. Deleted requirements for independent chemical analysis of each heat of controlled chemistry bars by the engineers.	Vendor has acceptable Category I QA program.	17.1; Table 1.8-1, RG 1.94
	b. Changed ASTM A615-Gr. 40 to A615-Gr. 60.	Vendor discontinued manufacturing certain size reinforcing bars in Gr. 40.	3.8.4
	c. Used high-strength reinforced steel in fuel pool beams and other miscellaneous areas of reactor building.	To minimize congestion in these areas.	3.8.4
Materials for construction - concrete	a. Revised requirements for aggregates.	Provided revised QA program requirements which conform to ANSI N45.2.5.	17.1; Table 1.8-1, RG 1.94

TABLE 1.3-9
(Sheet 5 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Materials for construction - concrete (cont'd.)	b. Minimum density revised downward for concrete used as biological shielding.	Radiation protection calculations show that average concrete density exceeds required value for radiological protection.	12.2.2, 3.8.4
	c. Added provisions for using heavy-density fill material (HDFM) in the biological shield wall.	To provide the necessary radiation protection and shielding capabilities.	3.8.3
	d. Porous concrete under reactor building mat uses calcium aluminate cement with no free calcium oxide or calcium carbonate.	Prevent lime buildup in mat drainage pipes.	3.8.4, 3.8.5
Waste solidification system	System uses asphalt to encapsulate waste prior to shipment offsite.	To meet future burial site restrictions on disposal of solidified waste.	11.4
SRV discharge device	Changed from "ramshead" to "T-quencher".	Improve thermal performance of suppression pool during SRV discharge.	App. 6A
115-kV switchyard	a. Added a bus section with necessary circuit switchers and isolation switches to feed the auxiliary boiler transformer.	To provide necessary 115-kV feed to the auxiliary boiler transformer.	8.2.1
	b. Outgoing cables to reserve transformers and auxiliary boiler transformer are routed overhead.	Since the switchyard has been moved close to the plant, this arrangement will improve reliability and maintainability of 115-kV offsite power.	
Auxiliary boiler transformer and switchgear	Added auxiliary boiler transformer and associated 13.8-kV switchgear.	To provide a separate power feed to the auxiliary boilers for startup and shutdown. Also, the 4.16-kV tertiary winding of the auxiliary boiler transformer provides a backup feed to the redundant Class 1E buses.	8.2.1, 8.3.1
Reserve transformers	Added tertiary windings to the reserve transformers.	To feed emergency buses to improve reliability of the Class 1E system.	8.2.1, 8.3.1
Normal and emergency ac distribution system	Revised distribution systems at 13.8-kV, 4.16-kV, and 600-V levels to include more 13.8-kV, 4.16-kV, and 600-V buses, to have offsite power as normal source to Class 1E buses and to have all load centers and MCCs double ended.	The new system design improves separation of non-Class 1E and Class 1E buses, improves reliability, availability, and maintainability of the plant ac distribution system.	8.3.1
Normal station service transformer	Increased in size from 75 to 100 MVA.	Increase in the normal Station auxiliary loads.	8.2.1, 8.3.1

TABLE 1.3-9
(Sheet 6 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
Auxiliary step-down transformer	Decreased in size from 12/16/20 MVA to 8.5/10.6/11.9 MVA.	Since Class 1E loads are fed from reserve transformers, the load on this transformer was reduced.	8.3.1
Normal load centers	Normal load center transformers (13.8 kV/600 V) increased in size from 1,000 kVA to 1,500/2,025 kVA and all normal load centers made double ended with two/three bus sections on 600-V buses.	Increased 600-V loads, allowance for future load growth, greater availability and maintainability of loads.	8.3.1
Emergency load centers	Division I and II emergency load center transformers (4.16 kV/600 V) increased in size from 1,000 kVA to 1,500/2,025 kVA.	Increase in 600-V emergency loads, allowance for future load growth.	8.3.1
Stub buses	Two 4.16-kV buses, 1,000/1,350-kVA load centers and MCCs were added to power loads needed to shut the plant down after a LOOP and a unit trip. These buses can be manually connected to be powered from the standby diesel generators.	This arrangement allows for an orderly shutdown of the plant upon a LOOP and unit trip.	8.3.1
Reactor recirculation system power supply	a. Added two Class 1E circuit breakers (Division I and II) in series to each recirculation pump. b. Added MG set and circuit breaker to each reactor recirculation pump to power the pumps during low plant power levels.	To assure trip of recirculation pump upon ATWS. MG sets run the recirculation pumps on 15-Hz power at 25% speed to preclude cavitation.	8.3.1
Degraded voltage relaying	Added additional set of undervoltage relays on Class 1E buses.	To detect slow degradation of voltage 4.16-kV Class 1E buses, to trip offsite power and power Class 1E buses from onsite diesel should offsite power supply voltage degrade to a point where operation of Class 1E equipment is endangered.	8.3.1
120-V ac Class 1E instrument power system	Added Class 1E UPSs.	To ensure availability of power to the Class 1E instrument buses that should not have power interruptions.	8.3.1
Diesel generators	The Division I and II diesel generators increased in size from 2,850 kW to 4,400 kW; Division III HPCS diesel generator increased from 2,500 kW to 2,600 kW.	Increase in Class 1E loads.	8.3.1

TABLE 1.3-9
(Sheet 7 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
250-V dc system	Deleted 250-V dc system and assigned all associated loads to 125-V dc system.	To reduce the number of normal batteries requiring maintenance.	8.3.2
Class 1E dc distribution system	Eliminated ties between safety-related 125-V dc systems and each Class 1E dc system is provided with a backup battery charger.	Ensures separation and independence of redundant Class 1E systems and improves reliability.	8.3.2
Cables	Non-Class 1E cables are colored black in lieu of white.	Regulatory guidance requires color coding.	8.3.1, 8.3.2
Separation	Separation in all tray, conduit, and other raceway systems revised to meet RG 1.75.	Issuance of RG 1.75.	8.3.1, 8.3.2
Plant communication	a. The number of party lines increased from three to five thereby increasing the total page and party communication channels from four to six. b. Added page line supervisory system. c. Added redundant communication paths in large areas.	To increase reliability and availability of the plant communication system.	9.5.2
Plant lighting system	a. Mercury vapor lighting fixtures changed to high-pressure sodium. b. Feed to the essential lighting subsystem changed to UPS. c. 8-hr battery-pack lighting added.	To upgrade the lighting system. To increase reliability of the essential lighting system. To meet the requirements of 10CFR50, Appendix R.	9.5.3
Outgoing transmission lines	Changed from 765 kV to 345 kV.	Economic advantage.	8.1
RCIC initiation	Trip of main turbine on an initiation of the RCIC turbine.	To prevent water induction.	5.4.6
Remote shutdown room	Remote shutdown room separated into two separate rooms with 3-hr rated barrier.	To meet the requirements of 10CFR50, Appendix R.	
Disconnect panels	Disconnect panels 2CES*PNL415 and 2CES*PNL416 added.	To isolate required circuits from the control room in the event of a control room fire (10CFR50, Appendix R).	

TABLE 1.3-9
(Sheet 8 of 8)

COMPARISON OF FINAL AND PRELIMINARY DESIGN INFORMATION FOR THE BALANCE OF PLANT (HISTORICAL)

Item	Change	Reason for Change	FSAR Reference
PSI of main steam lines	Up to turbine stop valves, including branch connection lines in main steam, main steam bypass lines 2 1/2-in diameter and larger, and up to and including the first stop valve in each line were examined in accordance with ASME Section XI, 1980 Edition, Winter 1980 Addenda, in lieu of that described in PSAR Section H.2.26.	To be consistent with overall in-service inspection (ISI) program.	5.2.4.8

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS (HISTORICAL)

1.4.1 Applicant

NMPC is a private, investor-owned utility involved in the generation, distribution, and selling of electrical power for residential, commercial, and industrial use. The utility has grown to its present status through the merger of many small companies, the oldest of which dates back to 1823. It presently serves over one million electrical customers in a 24,000 sq mi area of upstate New York.

NMPC is a utility experienced in the design and operation of generating facilities in both the conventional and nuclear fields. It operates 81 hydroelectric, 6 fossil-fueled, and 1 nuclear power unit, and has an installed capacity of over 3.5 million kW. It has been actively involved in the nuclear generating field since 1953. As a result of this experience, NMPC designed and is now operating Unit 1, a 1,850-MWt BWR nominally generating 610 MWe.

A sizable engineering staff in the corporate office in Syracuse, NY, consists of groups of disciplines required in the design and operation of generating stations. These groups are available to the Station staff for support and consultation as required.

On September 22, 1975, NMPC entered into an agreement with four electric utilities, whereby each of the utilities would own, as tenants in common, proportional interests in Unit 2. The names of these utilities and their proportional interests in Unit 2 are as follows:

Niagara Mohawk Power Corporation	41 percent
Central Hudson Gas & Electric Corporation	9 percent
Long Island Lighting Company	18 percent
New York State Electric & Gas Corporation	18 percent
Rochester Gas and Electric Corporation	14 percent

Under the terms of the agreement, the participants will share the electrical output and pay construction and operating costs according to their respective shares in Unit 2. The NRC approved the utilities' co-ownership in an amendment to the Unit 2 Construction Permit in October 1978[1]. NMPC has the responsibility for licensing, design, procurement, construction, operation, and all related functions with respect to Unit 2.

1.4.2 Architect-Engineer

Stone & Webster Engineering Corporation is a Massachusetts corporation with offices in Boston, MA; Cherry Hill, NJ;

Denver, CO; New York, NY; and Houston, TX. In addition to its project - dedicated staff, SWEC has utilized its own staff of specialists in various engineering disciplines to ensure that Unit 2 is designed in accordance with industry codes and standards and meets the requirements of the applicable federal, state, and local regulations for commercial nuclear power plants.

In addition to commercial nuclear power projects, SWEC has engaged in engineering, design, and construction of chemical refineries, hydroelectric stations, and fossil fuel power plants. It has participated in the design and construction of fossil fuel plants with a total capacity in excess of 41,000,000 kW. SWEC has been actively engaged in nuclear engineering and construction of nuclear power plants since 1954, with an accumulated experience in excess of 20,000,000 kW reactor thermal power. It has participated in the design and/or construction of the following nuclear power stations, all of which are operating or have operated successfully:

1. Shippingport Atomic Power Plant of Duquesne Light Company and ERDA.

2. Army Package Power Reactor (APPR, also known as SM-1).

3. Yankee Nuclear Power Station of Yankee Atomic Electric Company.

4. Carolinas-Virginia Tube Reactor of the Carolinas-Virginia Nuclear Power Associates, Inc.

5. Haddam Neck Plant of Connecticut Yankee Atomic Power Company.

6. Nine Mile Point Nuclear Station - Unit 1 of Niagara Mohawk Power Corporation.

7. Maine Yankee Atomic Power Station of Maine Yankee Atomic Power Company.

8. Surry Power Station Units 1 and 2 of Virginia Electric and Power Company.

9. James A. FitzPatrick Nuclear Power Plant - Unit 1 of the Power Authority of the State of New York.

10. North Anna Power Station Units 1 and 2 of Virginia Electric and Power Company.

11. Beaver Valley Power Station Unit 1 of Duquesne Light Company.

In addition to Unit 2, SWEC has under design or construction at this time the following nuclear power stations:

1. Beaver Valley Power Station Unit 2, Duquesne Light Company.

2. Millstone Nuclear Power Unit 3, Northeast Utilities Service Company.

3. River Bend Station Unit 1, Gulf States Utilities Company.

4. Shoreham Nuclear Power Station Unit 1, Long Island Lighting Company.

5. Enrico Fermi Unit 2, Detroit Edison Company.

In addition, SWEC is providing construction management services for the Demonstration Liquid Metal Fast Breeder Reactor Plant (Clinch River Project) and for the Gas Centrifuge Uranium Enrichment Plant by the U.S. Department of Energy.

1.4.3 Nuclear Steam Supply System

General Electric Company has been awarded contracts to design, fabricate, and deliver the direct-cycle boiling water NSSS, to fabricate the first core of nuclear fuel, and to provide technical direction of installation and startup of this equipment. GE has engaged in the development, design, construction, and operation of BWRs since 1955. Thus, GE has substantial experience, knowledge, and capability to design, manufacture, and furnish technical assistance for the installation and startup of reactors.

1.4.4 Turbine Generator Supplier

GE-LSTG (large steam turbine generator) has been awarded the contract for designing, fabricating, and delivering the turbine generator. GE I&SE (installation and service engineering) will provide technical assistance for installation and startup of this equipment. GE has a history in the application of turbine generators in nuclear power stations that dates back to the inception of nuclear facilities for the production of electrical power. GE has furnished the turbine generator units for 21 of the BWR plants that were on-line by 1977 and has scheduled orders to supply about 30 additional turbine generator units for use in BWR units. GE has also supplied or is scheduled to supply turbine generator units for approximately 60 pressurized water reactors (PWRs). GE's nonnuclear turbine experience is extensive. The ratings of these units range from 210 MW to over 1,100 MW. Thus, GE is technically qualified to design, fabricate, and deliver the turbine generator unit and to provide technical assistance for its installation and startup.

1.4.5 Technical Consultants

Dames & Moore

The independent consulting firm of Dames & Moore was employed in consultation for the preparation of the sections relating to hydrology, geology, and seismology. Having performed environmental studies for approximately 40 nuclear power plant sites, Dames & Moore is active in the field of environmental engineering related to nuclear power plant construction.

Listed below are some of the nuclear power plants for which Dames & Moore has performed environmental studies:

Plant	Company
Donald C. Cook	American Electric Power Company
Pilgrim	Boston Edison Company
Nine Mile Point Unit 1	Niagara Mohawk Power Corporation
Zion	Commonwealth Edison Company
Quad Cities	Commonwealth & Iowa - Illinois Gas & Electric Company
Midland	Consumers Power Company
Turkey Point	Florida Power & Light Corporation
Duane Arnold	Iowa Electric Light & Power Company
Peach Bottom	Philadelphia Electric Company
San Onofre	Southern California Edison Company
Salem	Public Service Electric and Gas Company
Seabrook	Public Service Company of New Hampshire
Wm. H. Zimmer	Cincinnati Gas & Electric Company; Columbus & Southern Ohio Electric Company; The Dayton Power and Light Company

Meteorological Evaluation Services, Inc.

The independent consulting firm of Meteorological Evaluation Services, Inc., (MES) was employed in the preparation of the meteorological section. MES is active in the field of environmental assessment, meteorological monitoring, and environmental studies for nuclear power plants.

Listed below are some of the nuclear power plants for which MES has performed environmental studies:

Plant	Company
Donald C. Cook	American Electric Power Service Corporation
Nine Mile Point Unit 1	Niagara Mohawk Power Corporation
James A. FitzPatrick	Power Authority of the State of New York
Limerick Generating Station Units 1 and 2	Philadelphia Electric Company
Peach Bottom Atomic Power Station Units 2 and 3	Philadelphia Electric Company
Salem Nuclear Generating Station Units 1 and 2	Public Service Electric & Gas Company
Hope Creek Nuclear Generating Stations Units 1 and 2	Public Service Electric & Gas Company

Lawler, Matusky & Skelly, Consulting Engineers

The environmental engineering consulting firm of Lawler, Matusky & Skelly Engineers (LMS) was employed for the preparation of the sections relating to aquatic biology, physical hydrology, lake circulation, temperature, and discharge evaluation. LMS has completed over 60 major projects that involved specialized environmental science and engineering services in such areas as CWS design, power plant siting, thermal discharge, biological surveys, impact assessment, mathematical modeling of biological populations, and regulatory aspects of nuclear, fossil-fueled, and hydroelectric power plant operations.

LMS has conducted hydrodynamic, physicochemical, and biological investigations for over 20 major electric utilities and utility associations throughout the U.S. The firm has conducted studies at 12 nuclear sites for 9 utilities.

Listed below are some of the nuclear power plants for which LMS has performed environmental studies:

Plant	Company
Brunswick	Carolina Power & Light Company
Indian Point Units 2 and 3	Consolidated Edison Company
Davids Island (proposed)	
Midland Units 1 and 2	Consumers Power Company
Oyster Creek	Jersey Central Power & Light Company
Nine Mile Point Units 1 and 2	Niagara Mohawk Power Corporation
Fort Calhoun	Omaha Public Power District
Pickering	Ontario Hydro
James A. FitzPatrick	Power Authority of the State of New York
San Onofre	Southern California Edison Company

1.4.6 Reference

1. U.S. NRC Construction Permit No. CPPR-112, Amendment No. 1, NRC Docket No. 50-410. Nine Mile Point Nuclear Station - Unit 2, Niagara Mohawk Power Corporation, October 27, 1978.

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

1.5.1 Current BWR Development Programs

1.5.1.1 Instrumentation for Vibration Detection

Vibration testing for reactor internals is performed for each GE BWR product line. At the time of issue of RG 1.20, test programs for compliance were instituted. The first BWR plant of each size and within each product line 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 prototypes are tested in compliance with the requirements of RG 1.20 to confirm the adequacy of the design with respect to vibration. Further discussion is presented in Section 3.9B.2.

1.5.1.2 Core Spray Distribution

The design basis for core spray distribution for BWR 5 plants is described in NEDO-10846 and NEDO-20566-3[1,2]. Other LOCA programs jointly sponsored by GE/NRC/EPRI show 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 fuel bundles. When this water inventory in the upper plenum subcools, the countercurrent flow limiting at the upper tie-plate breaks down, 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 be greater than the values prescribed by 10CFR50 Appendix K. This behavior has been verified by overseas testing and reported at the Ninth Water Reactor Safety Research Information Meeting, October 26-30, 1981[3].

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 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 for the central fuel rods of the bundle which improves heat transfer effectiveness.

There are two distinct programs involving the core spray performance evaluation. The core spray distribution adequacy has been verified and Licensing Topical Reports NEDO-10846 and NEDO-20566-3 have been submitted[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 Licensing Topical Report NEDO-10801[4].

The results of testing using Zircaloy cladding were reported in Licensing Topical Report NEDO-20231[5].

1.5.1.4 Verification of Pressure Suppression Design

The Mark II Pressure Suppression Test Program was initiated in the fall of 1975 to investigate suppression pool dynamic phenomena. Phase I blowdown tests were completed late in 1975. These tests utilized a single 24-in diameter (590-mm ID) downcomer that vented into a 7-ft (2.13-m) inside diameter tank, representative of a single downcomer/pool cell in a typical Mark II suppression pool. The objective of this phase of testing was to quantify pool dynamics phenomena, particularly on pool swell. In addition, data were recorded for the following, which at the time were considered of secondary importance: chugging, condensation oscillations, lateral loads, wetwell pressurization, diaphragm floor loading, and pool temperature distribution. Primary variables that were simulated are: break size, initial vent submergence, and wetwell air space configuration, i.e., vented or closed wetwell.

The Phase II tests were generally similar to the Phase I tests, except a 20-in diameter (489-mm ID) downcomer was used. The Phase I and II tests thus bound the range of vent to pool area ratios of all Mark II containments. Although the test objectives were similar during Phases I and II, some changes were made in the Phase II test matrix after review of the Phase I data. For example, since the Phase I test had shown that wetwell configuration was the variable that had the most pronounced effect on pool dynamics, the decision was made to concentrate the testing effort on the closed wetwell configuration, which is characteristic of the Mark II containment.

In place of the open wetwell tests, additional blowdowns were included in the Phase II test matrix in order to investigate the effect of saturated liquid versus saturated steam breaks and the effect of downcomer bracing configuration.

As was the case for the Phase I tests, the primary Phase II variables were simulated break size and initial vent submergence.

The Phase III tests investigated the pool temperature sensitivity of pool swell and of the load associated with the chugging phenomenon. Only a single break size and vent submergence were tested, with pool temperature alone being a variable. A significant number of blowdowns were performed to yield a statistically significant data set.

1.5.1.5 Boiling Transition Testing

Since the formulation of the 1966 Hench-Levy design limit lines for use in BWR thermal design, GE has continued to perform extensive steady-state and transient boiling test programs. Prior to 1974, over 14,000 data points had been obtained from

test assemblies having various axial heat flux profiles and rod-to-rod power distributions, covering prototypical aspects of reactor operating conditions. Among these, 2,100 data points were full-scale simulation of 7x7 and 8x8 BWR fuel assemblies performed in the ATLAS test facility. A new boiling transition correlation (GEXL) was developed and applied to GE BWR thermal design. Detailed information is provided in the approved Licensing Topical Report, NEDO-10958A[6].

Since the implementation of the GEXL correlation on design in 1974, GE has continued to conduct full-scale 8x8 assembly boiling transition tests. These tests have accumulated over 1,600 data points after GE thermal analysis basis (GETAB) introduction, to extend the data base and assure applicability to new 8x8 fuel designs such as the two-water-rod design for BWR 2 through BWR 6. It has been shown that the 8x8 GEXL correlation with the appropriate R-factors can predict boiling transition critical power data for the two-water-rod assemblies, with an accuracy typical of the GEXL correlation predictability for other 8x8 designs as described in NEDO-10958A[6].

1.5.2 Geotechnical Investigations

This section presents a summary of programs in geology, seismology, and geotechnical engineering that were undertaken to ensure conservative final design parameters for plant structures, systems, and components.

In September 1976, several small low-angle thrust faults and associated low-amplitude folds were discovered in the bedrock during excavation of plant structures such as the heater bay. Additionally, high-angle faults with associated buckles were discovered in the excavation for the cooling tower structure and in the drainage ditch. Excavations in April 1979 revealed small zones of bedding plane slip and folding in the circulating water trenches. Small low-angle thrust faults were observed in the radwaste excavation and in each lake-water tunnel in late 1979 and early 1980.

Each of these geologic conditions was studied in detail and reports were developed and submitted to the NRC to describe their safety significance. The detailed studies included a description of the origin, age, and significance of these features. As part of the then ongoing evaluation, the reports were submitted to the NRC for review and meetings were held to respond to NRC questions.

Geologic investigations at the site indicated that conditions of in situ stress, rock lithology and anisotropy, and groundwater fluctuations are elements that had to be considered in the design. To further support the geologic investigations, a geologic monitoring program was initiated. This program is currently collecting data and will be completed by January

1985.The results of the monitoring program will be submitted as amendments to the FSAR.

A further description of the features and their significance is provided in Section 2.5.

1.5.3 References

1. BWR Core Spray Distribution, NEDO-10846, April 1973.

2. General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 - Appendix K - Effect of Steam Environment on BWR Core Spray Distribution, NEDO-20566-3, April 1977.

3. Sozzi, G. L. and Lee, L. S. BWR Blowdown/Emergency Core Cooling Integral Test Program Final Results from the Two Loop Test Apparatus (TLTA), October 26, 1981.

4. Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness, NEDO-10801, March 1973.

5. Emergency Core Cooling Tests of an Internally Pressurized Zircaloy Clad, 8x8 Simulated BWR Fuel Bundle, NEDO-20231, December 1973.

6. General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application, NEDO-10958A, January 1977.

1.6 MATERIAL INCORPORATED BY REFERENCE

Table 1.6-1 is a list of all topical reports and any other report or document which are incorporated in whole or in part by reference in this USAR and have been filed with the NRC.

Table 1.6-2 is a list of Technical Requirements Manual (TRM) sections which are incorporated into the USAR by reference.

Additional documents referenced in this USAR are listed at the end of the sections in which they have been referenced.

TABLE 1.6-1
(Sheet 1 of 5)

REFERENCED REPORTS FOR THE NSSS SCOPE OF SUPPLY

REPORT NUMBER	TITLE	REFERENCED IN SECTION
A. GE Reports		
APED-4378	Maximum Flow Rate of a Single Component Two-Phase Mixture (October 25, 1963)	6.2
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, 6B
APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)	4.6
APED-5696	Tornado Protection for Spent Fuel Storage Pool (November 1968)	3.3.2
APED-5706	In-Core Neutron Monitoring System for General Electric Boiling Water Reactors (November 1968, Revised May 1969)	6A, 7.6
APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Isolation Valves (March 1969)	3.9B, 5.4
APED-5756	Analytical Methods for Evaluating the Radiological Aspects of General Electric Boiling Water Reactors (March 1969)	15.4
GEAP-5620	Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws	5.2
NEDC-30088	Responses to NRC Post-Implementation Review Criteria for Post-Accident Sampling System	1.10
NEDC-33045P	Methods of Estimating Core Damage in BWRs (July 2001)	1.10
NEDE-10313	PDA-Pipe Dynamic Analysis Program for Pipe Rupture Movement (Proprietary Filing)	3.6B.3
NEDE-20566	Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K (Proprietary Document)	3.9B.6, 6.3
NEDE-20944-P-1	BWR/4 and BWR/5 Fuel Design (October 1976) (Amendment 1, January 1977) (only BWR/4 and 5)	4.2 and 4.3
NEDE-21078	Test Results Employed by GE for BWR Containment and Vertical Vent Loads	6A
NEDE-21175-3-P	BWR Fuel Channel Mechanical Design and Deflection (September 1976)	6A
NEDE-21471-P	Analytical Model for Estimating Drag Forces on Rigid Submerged Structures Caused by LOCA and Safety Valve Ramshead Air Discharge	3.9, 3A.13.1

TABLE 1.6-1
(Sheet 2 of 5)

REFERENCED REPORTS FOR THE NSSS SCOPE OF SUPPLY

REPORT NUMBER	TITLE	REFERENCED IN SECTION
NEDE-21544-P	Mark II Pressure Suppression Containment Systems: An Analytical Model of the Pool Swell Phenomenon (December 1976)	6A
NEDC-33351P	Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate	4.3, 4.4
NEDE-21730	Mark II Pressure Suppression Containment Systems - Loads on Submerged Structures, An Application Memorandum (December 1977)	3A.13.1
NEDE-21821-02	Boiling Water Reactor Feedwater Nozzle/Sparger Final Report (August 1979)	5.3
NEDE-22178-PA	Mark II Containment Drywell to Wetwell Vacuum Breaker Models	6.2
NEDE-23014	Hex 01 User's Manual (July 1976)	15.2
NEDO-24010-P	Technical Basis for the Use of the Square Root of the Sum of Squares (SRSS) Method for Combining Dynamic Loads for Mark II Plants (Supplement 1, October 1978) (Supplement 2, December 1978) (Supplement 3, August 1979)	6A
NEDE-24011-P-A NEDE-24011-P-A-US	General Electric Standard Application for Reactor Fuel Including United States Supplement (latest approved revision)	4.1, 4.2, 4.3, 4.4, 5.2, 6.3, 15.3, 15.4
NEDE-24057-P NEDE-2-P-24075 NEDO-24075-1-P	Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants (Class III) (November 1977) and Amendment 1 (December 1978), Amendment 2 (June 1979)	3.9, 6B
NEDE-24222	Assessment of BWR Mitigation of ATWS (Vol. I, II) (May, December 1979)	15.8
NEDE-24302-P	Generic Chugging Load Definition Report	6A, 3A.26.3
NEDE-24326-1-P	Environmental Qualification Program Class IV (January 1983)	3.11
NEDE-24822-P	Mark II Improved Chugging Methodology, Class III (May 1980)	3A.12.1
NEDE-24988-P	Analysis of Generic BWR Safety/Relief Valve Operability Test Results	6A
NEDO-10173	Current State of Knowledge, High Performance BWR Zircaloy-Clad UO_2 Fuel (May 1973)	11.1
NEDO-10349	Analysis of Anticipated Transients Without Scram (March 1971)	15.8
NEDO-10466-A	Power Generation Control Complex Design Criteria and Safety Evaluation	9.5

TABLE 1.6-1
(Sheet 3 of 5)

REFERENCED REPORTS FOR THE NSSS SCOPE OF SUPPLY

REPORT NUMBER	TITLE	REFERENCED IN SECTION
NEDO-10505	Experience with BWR Fuel Through September 1971 (May 1972)	11.1
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, 15A
NEDO-10801	Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness (March 1973)	1.5
NEDO-10802	Analytical Methods of Plant Transient Evaluations for General Electric Boiling Water Reactor (February 1973)	15.0, 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-10905	HPCS Power Supply Topical Report	6A
NEDO-10958-A	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (January 1977)	1.5, 4.4.2, 16.1, 15.0
NEDO-20231	Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8X8 Simulated BWR Fuel Bundle (December 1973)	1.5
NEDO-20533	The General Electric Mark III Pressure Suppression Containment System Analytical Model (June 1974)	3B.4, 15.2
NEDO-20566-3	General Electric Company Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K - Effect of Steam Environment on BWR Core Spray Distribution (April 1977)	1.5, 6.3
NEDO-20626	Studies of BWR Designs for Mitigation of Anticipated Transients Without Scrams (October 1974)	15.8
NEDO-20626-1	Studies of BWR Designs for Mitigation of Anticipated Transients Without Scrams (June 1975)	15.8
NEDO-20626-2	Studies of BWR Designs for Mitigation of Anticipated Transients Without Scrams (July 1975)	15.8
NEDO-20913	Lattice Physics Methods	9.1
NEDO-20922	Experience with BWR Fuel Through September 1974 (June 1975)	11.1
NEDO-20944	BWR/4 and BWR/5 Fuel Design (October 1976)	4.2 and 4.3

TABLE 1.6-1
(Sheet 4 of 5)

REFERENCED REPORTS FOR THE NSSS SCOPE OF SUPPLY

REPORT NUMBER	TITLE	REFERENCED IN SECTION
NEDO-21061-3	Mark II Containment Dynamic Forcing Functions Information Report (June 1978), also Revision 4 (November 1981)	3.9B.6, 6A, 3A.13.3
NEDO-21064-4	Mark II Containment Dynamic Forcing Functions	6A
NEDO-21143-1	Radiological Accident Evaluation - The CONCACO3 Code (December 1981)	15.6
NEDO-21159	Airborne Release from BWRs for Environment Impact Evaluations (March 1976)	11.1
NEDO-21231	Banked Position Withdrawal Sequence	15.4
NEDO-21506	Stability and Dynamic Performance of the General Electric Boiling Water Reactor (January 1977)	4.1.5
NEDO-21660	Experience with BWR Fuel Through December 1976 (July 1977)	11.1
NEDO-21778	Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors (December 1978)	5.3
NEDO-21985	Functional Capability Criteria for Essential Mark II Piping (September 1978)	6A.9.1.1.2, 3.9A.3
NEDO-24057	Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants (Class I) (November 1977)	3.9B.6
NEDO-23538	Users Manual for CRPLS01 Computer Program (December 1976)	4.1.5
NEDO-24154-P	Qualification of One-Dimensional Core Transient Model for BWR	15.0, 15.1
NEDO-24210	Analysis of WRC Problem (August 1979)	3.9B.6
NEDO-24548	Annulus Pressurization Load Adequacy Evaluation (January 1979)	6.2
NEDO-32991-A	Regulatory Relaxation for BWR Post-Accident Sampling Stations (PASS) (August 2001)	1.10, 7.5

TABLE 1.6-1
(Sheet 5 of 5)

REFERENCED REPORTS FOR THE NSSS SCOPE OF SUPPLY

REPORT NUMBER	TITLE	REFERENCED IN SECTION
B. Other Reports		
BHR/DER 70-1	Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor (March 1970)	11.1
SWECO-7703	Missile-Barrier Interaction (September 1977)	3.5.3
WPC-VRS-001	Radwaste Volume Reduction and Solidification System (May 1978)	11.4.7
WPC-VRS-002	10CFR61 Waste Form Conformance Program for Solidified Waste Products Produced by a Wastechem Corporation Volume Reduction and Solidification System (August 1987)	11.4.7
SWECO-8101	Models used in LOCTVs - A Computer Code to Determine Pressure and Temperature Response of Vapor Suppression Containments Following a Loss-of-Coolant Accident (1981)	6.2.1
EN-136	Stone & Webster Engineering Corporation Shallow Water Wave Generation (SWWAVE) Proprietary User's Manual (January 1977)	2.4.15
ORNL-NISC-22	Missile Generation and Protection in Light Water-Cooled Power Reactor Plants (September 1968)	3.5.4
GEN-02-02	Final Report Pipe Rupture Analysis of Recirculation System for 1965 Standard Plant Design	3.6B.3
RP-8A	Radiation Shielding Design and Analysis Approach for Light Water Reactor Power Plant (May 1975)	12.3
SRLR	Supplemental Reload Licensing Report	9.3, A.4.3, A.6, A.15

TABLE 1.6-2
(Sheet 1 of 2)

TECHNICAL REQUIREMENTS MANUAL INFORMATION INCORPORATED BY REFERENCE

TRM SECTION	TITLE	REFERENCED IN SECTION/TABLE
3.1.4	Control Rod Scram Times <800 psig	4.6.3.1.1
3.3.1.1	Reactor Protection System (RPS) Response Time	7.2.1.3
3.3.1.2	Reactor Protection System (RPS) Shorting Links	15E.3
3.3.2	Control Rod Block Instrumentation	7.7.1.1.2, Table 7.3-17
3.3.3.1	Non-Type A, Non-Category 1 Post-Accident Monitoring Instrumentation	7.5.2
3.3.3.2	Remote Shutdown System	7.4.1.5.2
3.3.4	End of Cycle Recirculation Pump Trip (EOC-RPT) System Response Time	7.6.1.5
3.3.5	Emergency Core Cooling System (ECCS) Instrumentation	7.3.1.1.1.2
3.3.6.1	Primary Containment Isolation System Response Time	7.3.1.1.2
3.3.6.2	Primary Containment Isolation Instrumentation	Table 7.3-17
3.3.7.1	Area Radiation Monitoring Instrumentation	12.3.4.1.5
3.3.7.2	Seismic Monitoring Instrumentation	Table 1.9-1
3.3.7.3	Traversing In-Core Probe	7.7.1.7.1.2
3.3.9	Service Water System Instrumentation	9.2.1.5
3.3.10	Meteorological Monitoring Instrumentation	2.3.3.2.4
3.3.11	Offgas System Explosive Gas Monitoring	11.3.1
3.4.1	Reactor Coolant System (RCS) Chemistry	5.2.3.2.2
3.4.2	Structural Integrity	3.9A.3.1
3.4.6	Pressure Isolation Valves	7.6.2.2.2
3.4.8	Reactor Coolant System (RCS) Specific Activity	11.5.3
3.5.1	Emergency Core Cooling System (ECCS) Response Time	7.3.1.1.1

TABLE 1.6-2
(Sheet 2 of 2)

TECHNICAL REQUIREMENTS MANUAL INFORMATION INCORPORATED BY REFERENCE

TRM SECTION	TITLE	REFERENCED IN SECTION/TABLE
3.6.1	Primary Containment Isolation Valves	6.2.4.4
3.6.4.1	Secondary Containment	6.2.3.4
3.6.4.2	Secondary Containment Isolation Valves	6.2.3.4
3.6.4.3	Standby Gas Treatment System	6.5.1.4.2
3.7.1	Service Water (SW) System - Shutdown	9.2.1.3
3.7.2	Control Room Envelope Filtration System	6.4.5
3.7.3	Snubbers	3.9B.3.4.1
3.7.4	Sealed Source Contamination	12.5.3.7
3.7.5	Main Turbine Bypass System	10.4.4.5
3.7.6	Revetment-Ditch Structure	2.4.14
3.7.7	Liquid Holdup Tanks	11.2.1.2
3.7.8	Explosive Gas Mixture	10.4.2.5
3.8.2.1	AC Circuits Inside Primary Containment	8.3.1.1.5
3.8.2.2	Primary Containment Penetration Conductor Overcurrent Protective Devices	8.3.1.1.5
3.8.2.3	Emergency Lighting Systems	8.3.1.1.5
3.9.2	Decay Time	9.1.4.2.11
3.9.3	Communications	9.1.4.2.11
3.9.4	Refueling Platform	9.1.4.4.2
3.9.5	Crane Travel - Spent Fuel Storage Pool	9C.8.1
3.11.1	Solid Radioactive Wastes	11.4.3.6

1.7 DRAWINGS AND OTHER DETAILED INFORMATION

The drawings listed in this section were provided to assist the NRC in the FSAR review.

1.7.1 Electrical, Instrumentation, and Control Drawings

Table 1.7-1 of the FSAR contains a list of safety-related electrical, instrumentation, and control drawings which were submitted separate from the FSAR. This table is not maintained in the USAR. For reference, see FSAR Table 1.7-1.

1.7.2 Piping and Instrumentation Diagrams

Table 1.7-2 contains a list of system piping and instrumentation diagrams (P&ID) provided in the USAR. P&ID symbols used on Unit 2 diagrams are shown on Figure 1.7-1; those used on GE diagrams are shown on Figure 1.7-2. Figure 1.7-3 shows logic symbols used on Unit 2 logic diagrams. Figure 1.7-4 shows symbols used on Unit 2 electrical one-line diagrams.

TABLE 1.7-1

THIS TABLE HAS BEEN DELETED.

REFERENCE SAME TABLE IN FSAR.

TABLE 1.7-2
(Sheet 1 of 3)

PIPING AND INSTRUMENTATION DIAGRAMS

FSAR Figure No.	Title
4.6-5 a-c	Control Rod Drive Hydraulic System P&ID (RDS)
5.1-2 a-c	Nuclear Boiler and Process Instrumentation P&ID (ISC)
5.4-2 a-d	Reactor Recirculation System P&ID (RCS)
5.4-9 a-d	Reactor Core Isolation Cooling System P&ID (ICS)
5.4-13 a-g	Residual Heat Removal System (RHS)
5.4-16 a-f	Reactor Water Cleanup System P&ID (WCS)
6.2-71 a&b	Containment Atmosphere Monitoring System P&ID (CMS)
6.2-72 a&b	DBA Hydrogen Recombiners System P&ID (HCS)
6.2-73 a	Containment Leakage Monitoring System P&ID (LMS)
6.3-6 a&b	High Pressure Core Spray System P&ID (CSH)
6.3-7 a	Low Pressure Core Spray System P&ID (CSL)
9.1-5 a-d	Spent Fuel Pool Cooling and Cleanup System P&ID (SFC)
9.1-26 a	Decontamination System P&ID (DCS)
9.2-1 a-q	Service Water System P&ID (SWP)
9.2-3 a-g	Reactor Building Closed Loop Cooling Water System P&ID (CCP)
9.2-5 a-e	Water Treatment System P&ID (WTS)
9.2-6 a	Makeup Water System P&ID (MWS)
9.2-8 a&b	Domestic Water System P&ID (DWS)
9.2-9 a&b	Sanitary Drains and Disposal System P&ID (PBS)

TABLE 1.7-2
(Sheet 2 of 3)

PIPING AND INSTRUMENTATION DIAGRAMS

FSAR Figure No.	Title
9.2-17 a-c	Condensate Storage and Transfer System P&ID (CNS)
9.2-19 a-f	Turbine Building Closed Loop Cooling Water System P&ID (CCS)
9.3-1 a-m	Instrument and Service Air Systems P&ID (IAS)
9.3-3 a-e	Breathing Air System P&ID (AAS)
9.3-5 a-k	Process Sampling System P&ID (SSR)
9.3-9 a-f	Reactor Building Drains and Drywell Equipment and Floor Drains P&ID (DER)
9.3-10 a-j	Turbine Building Drains P&ID (DET)
9.3-11 a-e	Radwaste Building Drains P&ID (DFW)
9.3-12 a-l	Miscellaneous Drains P&ID (DFM)
9.3-17 a	Standby Liquid Control System P&ID (SLS)
9.3-20 a&b	Nitrogen System P&ID (GSN)
9.4-1 a-f	Control Building HVAC System P&ID (HVK, HVC)
9.4-2 a-e	Miscellaneous HVAC Systems P&ID (HVC, HVL, HVI, HYV)
9.4-3 a-f	Normal Switchgear Building HVAC System P&ID
9.4-8 a-l	Reactor Building HVAC Systems P&ID (HVR, DRS, CPS, GTS)
9.4-10 a-e	Radwaste Building HVAC System P&ID (HVW)
9.4-12 a-d	Turbine Building HVAC System P&ID (HVT)
9.4-15 a	Diesel Generator Building HVAC System P&ID (HVP)
9.4-22 a-e	Plant Hot Water Heating and Glycol Heating Systems P&ID (HVH)
9.5-1 a-h	Fire Protection Water System P&ID (FPW)

TABLE 1.7-2

PIPING AND INSTRUMENTATION DIAGRAMS

FSAR Figure No.	Title
9.5-2 a&b	Fire Protection Foam System P&ID (FPF)
9.5-3 a-c	Fire Protection CO_2 System P&ID (FPL)
9.5-4 a	Fire Protection Halon System P&ID (FPG)
9.5-40 a-c	Standby Diesel Generator System P&ID (EGA, EGF)
9.5-52 a-c	Auxiliary Boiler System P&ID (ABM)
10.1-3 a-k	Main Steam System P&ID (MSS)
10.1-4 a-d	Moisture Separators and Reheaters P&ID (CRS)
10.1-5 a-e	Condensate System P&ID (CNM)
10.1-6 a-e	Feedwater System P&ID (FWS)
10.1-7 a-w	Feedwater Heater System and Extraction Steam System P&ID (ESS)
10.1-8 a-g	Turbine Generator Gland Seal and Exhaust System P&ID (CNA)
10.1-9 a-h	Condensate Demineralizer System P&ID (CND)
10.4-2 a	Condenser Air Removal System P&ID (ARC)
10.4-7 a-h	Circulating Water, Acid and Hypochlorite Systems P&ID (CWS)
11.2-1 a-m	Radioactive Liquid Waste System P&ID (LWS, SWR)
11.3-1 a-c	Offgas System P&ID (OFG)
11.4-1 a-h	Radioactive Solid Waste System P&ID (WSS)

1.8 CONFORMANCE TO NRC REGULATORY GUIDES

Tables 1.8-1 and 1.8-2 indicate the extent of compliance with all applicable NRC Regulatory Guides and the revision number of those guides. A reference to the USAR section(s) in which the applicable design features are described is also provided.

Where the design differs from the regulatory guides, alternative methods of providing an equivalent level of safety have been utilized. These differences are discussed in Tables 1.8-1 and 1.8-2, or reference is made to the appropriate USAR section(s) in which they are discussed.

TABLE 1.8-1
(Sheet 1 of 49)

CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.1, REVISION 0 (NOVEMBER 1970) - NET POSITIVE SUCTION HEAD FOR EMERGENCY COOLING AND CONTAINMENT HEAT REMOVAL SYSTEM PUMPS

FSAR Section 6.3.2.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The physical location of the RHR, LPCS, and HPCS pumps in relation to the minimum suppression pool water level is such that the required NPSH is maintained on these pumps under the conditions of zero psig containment pressure and 212°F suppression pool water temperature for all operating modes. Adequate NPSH is verified by system calculations.

REGULATORY GUIDE 1.2, REVISION 0 (NOVEMBER 1970) - THERMAL SHOCK TO REACTOR PRESSURE VESSELS

FSAR Section 5.3.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

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

FSAR Sections 3.11.5, 15.6.5

Position Evaluation of the radiological consequences of a loss-of-coolant accident is based on RG 1.183; therefore, this regulatory guide is not applicable to the Unit 2 project for offsite and control room doses. RG 1.3 assumptions are used to evaluate equipment qualification doses and access to vital areas.

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

Position RG 1.4 applies to PWR plants and therefore is not applicable to Unit 2.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.5, REVISION 0 (MARCH 1971) - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAK ACCIDENT FOR BOILING WATER REACTORS FSAR Section 15.6.4 Position Evaluation of the radiological consequences of a steam line break accident is based on RG 1.183; therefore, this regulatory guide is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.6, REVISION 0 (MARCH 1971) - INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS FSAR Sections 8.3.1.2, 8.3.2.2 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide for Division I, II, and III diesels.
REGULATORY GUIDE 1.7, REVISION 2 (NOVEMBER 1978) - CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS-OF-COOLANT ACCIDENT FSAR Sections 6.1.1.2, 6.2.5 Position Unit 2 complies with the Regulatory Position (Paragraph C) of this guide. Conformance with this guide is achieved by redundant recombiner systems. The Unit 2 design includes the recombiners and an inerted containment which is described in Section 6.2.5.2.3.
REGULATORY GUIDE 1.8, REVISION 1-R (MAY 1977) - PERSONNEL SELECTION AND TRAINING FSAR Section Chapter 13 Position Unit 2 complies with RG 1.8 Revision 1-R (May 1977) in meeting the criteria for the selection and initial training of nuclear power plant personnel as contained in ANSI N18.1. Unit 2 complies with 10CFR55 and maintains a Licensed Operator Requalification Program based on the systems approach to training (SAT) concept. This is delineated in Nine Mile Point Nuclear Station Site Administration Procedures which will be followed while staffing Unit 2.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.9, REVISION 2 (DECEMBER 1979) - SELECTION OF DIESEL GENERATOR SET CAPACITY FOR STANDBY POWER SUPPLIES

FSAR Section 8.3.1.2

Position The criteria used in the selection, design, qualification, and testing of the Unit 2 Division I and II standby diesel generators comply with the Regulatory Position (Paragraph C) of this guide.

The Division III diesel generator (HPCS) conforms to Regulatory Positions C.1, C.2, and C.3 of this guide. The HPCS diesel generator performance is considered an acceptable departure from literal conformance to Regulatory Position C.4.

Environmental qualification of the Division III diesel generator is discussed in Section 3.11; testability is discussed in RG 1.108.

REGULATORY GUIDE 1.10, REVISION 1 (JANUARY 1973)* - MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CATEGORY I CONCRETE STRUCTURES

FSAR Section 3.8.4.6.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, with the following alternative approaches:

1. Paragraph C.2 Visual inspection of mechanical splices prior to forming will be performed on each splice by the Cadwelder and on a random basis (20 percent) by field quality control (FQC).

2. Paragraph C.3b The locations of all mechanical splices for reinforcing bars are shown on permanent plant records that are kept for the plant lifetime.

3. Paragraph C.4a Reinforcing bars with a radius of curvature of 60 ft 0 in or greater are tested at the sampling frequency specified in Paragraph C.4a. Reinforcing bars with a radius of curvature of less than 60 ft are tested using only sister splices with the following frequency for each splicing crew:

   1 sister splice for the first 10 production splices.

   4 sister splices for the next 90 production splices.

   3 sister splices for the next and subsequent units of 100 production splices.

   If any sister splice used for tensile testing fails to equal or exceed 125 percent of the minimum yield strength specified for the reinforcing bar, or the average tensile strength of each group of 15 consecutive samples fails to equal or exceed the guaranteed minimum tensile strength of the reinforcing bar, the individual Cadwelder is stopped and the procedure in Section C.5 of the regulatory guide is followed.

4. Paragraph C.5a If any completed mechanical splice fails to pass the individual inspection, and the rate of splices that fail the visual inspection does not exceed 1 for each 15 consecutive observed splices, the sampling program is started anew without requalifying the crew. If the failure rate exceeds 1 in 15 the crew is requalified.

* This regulatory guide was withdrawn on July 8, 1981, by the NRC. It has been superseded by RG 1.136 Revision 2 (June 1981).

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.10, REVISION 1 (JANUARY 1973)* (cont'd.)

For tests failing the second criterion of two or more splices for any six additional samples, it is considered that the failure rate pertains to the total output of all splicers, and the previous 100 splices are evaluated accordingly.

Conformance to this guide is ensured through a purchase specification.

REGULATORY GUIDE 1.11, REVISION 0 (MARCH 1971) - INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT

FSAR Sections 6.2.4, 7.1.2.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

Instrument lines penetrating the containment are designed in accordance with this regulatory guide.

REGULATORY GUIDE 1.12, REVISION 1 (April 1974) - INSTRUMENTATION FOR EARTHQUAKES

FSAR Section 3.7A.4.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The technical requirements of the regulatory guide are implemented in the seismic portions of the procurement specification for seismic instrumentation.

REGULATORY GUIDE 1.13, REVISION 1 (DECEMBER 1975) (FOR COMMENT) - SPENT FUEL STORAGE FACILITY DESIGN BASIS

FSAR Sections 9.1.2, 9.1.3, 9.1.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The design of the spent fuel storage facility incorporates the guidance listed in the regulatory position to assure that the fuel storage facility maintains the capability to perform its safety functions. An analysis of tornado protection for spent fuel storage is documented in a GE report entitled, Tornado Protection for Spent Fuel Storage Pool, APED-5696, November 1968.

REGULATORY GUIDE 1.14, REVISION 1 (AUGUST 1975) (FOR COMMENT) - REACTOR COOLANT PUMP FLYWHEEL INTEGRITY

Position This regulatory guide is not applicable to BWRs.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.15, REVISION 1 (DECEMBER 1972)* - TESTING OF REINFORCING BARS FOR CATEGORY I CONCRETE STRUCTURES

FSAR Sections 3.8.3, 3.8.4, 3.8.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide. Conformance to this regulatory guide is ensured through the purchase specification for reinforcing bars.

* This regulatory guide was withdrawn on July 8, 1981, by the NRC.

REGULATORY GUIDE 1.16, REVISION 4 (AUGUST 1975) (FOR COMMENT) - REPORTING OF OPERATING INFORMATION - APPENDIX A TECHNICAL SPECIFICATIONS

FSAR Sections Chapter 16, Technical Specifications

Position Unit 2 complies with Generic Letter 97-02 (May 5, 1997) in meeting the criteria of reporting of operating information.

This is delineated in the Nine Mile Point Nuclear Station Site Administration Procedure that is incorporated in the Technical Specifications for Unit 2.

REGULATORY GUIDE 1.17, REVISION 0 (JUNE 1973) - PROTECTION OF NUCLEAR POWER PLANTS AGAINST INDUSTRIAL SABOTAGE

FSAR Section 13.6

Position The Unit 2 project designs, procures, and installs Unit 2 plant equipment and structures in accordance with this regulatory guide.

The Unit 2 project ensures that compliance is achieved by the following methods:

1. The Unit 2 project Security Design Review Committee reviews the design and arrangement of security-related plant equipment and structures for conformance with the position outlined above.

2. The Unit 2 project controls accessibility to Unit 2 security-related materials.

Tests and operability checks will be performed as required by this regulatory guide.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.18, REVISION 1 (DECEMBER 1972)* - STRUCTURAL ACCEPTANCE TESTS FOR CONCRETE PRIMARY REACTOR CONTAINMENTS

FSAR Section 3.8.1

Position The Unit 2 project will comply with the Regulatory Position (Paragraph C) of this guide.

On February 10, 1976, NMPC transmitted the report, Primary Containment Structural Acceptance Test, to the NRC. This report describes the structural acceptance test in accordance with Section 13.6.3.38.2 of the PSAR.

Conformance with this guide is provided by a test procedure outlined in Section 3.8.1.7.1.

* This regulatory guide was withdrawn on July 8, 1981, by the NRC. It has been superseded by RG 1.136 Revision 2 (June 1981).

REGULATORY GUIDE 1.19, REVISION 1 (AUGUST 1972)* - NONDESTRUCTIVE EXAMINATION OF PRIMARY CONTAINMENT LINER WELDS

FSAR Section 3.8.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) with the following alternate approaches:

1. Nondestructive test methods (Paragraph C.2.a) and acceptance standards (Paragraphs C.7.a, C.7.b, C.7.d) are in accordance with the effective ASME Section III addenda which correspond to the referenced Subarticle NE-5120.

2. Leak-tightness testing of leak chase system channel-to-liner welds will be in accordance with Paragraph C.1.d or methods of equal or greater sensitivity, such as halide leak detector testing or pressure testing with bubble solutions.

3. Liner seam welds that are not accessible for radiography after construction (Paragraph C.1.b) may be examined by the liquid penetrant method, magnetic particle method, or ultrasonic method.

4. The following are exceptions to Paragraph C.3:

   a. An exception is taken regarding the qualification of welders who welded the CRD insert and withdrawal piping instrumentation, and temperature monitoring penetration adaptor to sleeve welds. These welders were initially qualified to the rules of ASME IX except that their qualification for small-diameter pipe employed incorrect bend diameters. The welders were subsequently qualified to the full provisions of ASME IX.

   b. An exception is taken regarding the qualification of the thermit welding process used to connect copper electrical grounding cables to the concrete side of thickened areas of the liner. The adequacy of this procedure was demonstrated by sectioning and metallurgically examining sample welds.

* This regulatory guide was withdrawn on July 8, 1981, by the NRC. It has been superseded by RG 1.136 Revision 2 (June 1981).

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.19, REVISION 1 (AUGUST 1972)* (cont'd.)

5. An exception to Paragraph C.2 is taken regarding the documentation reports for the nondestructive examination (NDE) of certain hatch and airlock welds. NDE reports for some welds in the personnel airlock, escape airlock, equipment hatches, and suppression chamber access hatch contain conflicting dates and, consequently, do not provide complete evidence of NDE. Subsequent review of documentation, engineering evaluation, and satisfactory pressure and leak tests demonstrates that the welds will maintain their structural integrity and leak-tightness.

REGULATORY GUIDE 1.20, REVISION 2 (MAY 1976) - COMPREHENSIVE VIBRATION ASSESSMENT PROGRAM FOR REACTOR INTERNALS DURING PREOPERATIONAL AND INITIAL STARTUP TESTING

FSAR Sections 3.9B.2.4, 14.2.7, 14.2.12

Position NSSS analysis, design, and/or equipment utilized in this facility is in compliance with the intent of the subject regulatory guide through the incorporation of the alternate approach discussed in Section 3.9B.2.4.

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 EFFLUENT FROM LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

FSAR Section 11.5.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

Unit 2 will submit annual reports specifying effluent release information to the NRC as required by 10CFR50.36a(a).(2), Technical Specifications on Effluents from Nuclear Power Reactors.

REGULATORY GUIDE 1.22, REVISION 0 (FEBRUARY 1972) - PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS

FSAR Sections 7.2.2.3, 7.3.2.1, 7.4.2.1, 7.6.2.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide as discussed in applicable portions of Chapter 7.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.23, REVISION 0 (FEBRUARY 1972) - ONSITE METEOROLOGICAL PROGRAM FSAR Section 2.3.3 Position Unit 2 complies with RG 1.23 (Safety Guide 23) (February 1972). However, the wind speed sensor in use at the 200-ft level until July 1982 did not meet the requirements of the guide. The new sensor installed after July 1982 has the starting speed and accuracy specified by the regulatory guide. The severe weather conditions encountered at Nine Mile Point lead to the choice of the very rugged wind speed sensor installed in November 1972. It had a starting speed of about 2.6 mph and would continue to operate with speeds of 1 to 1.5 mph. The wind speed accuracy is ±1.0 mph above 10 mph as opposed to the RG 1.23 Criterion I 0.5 mph for all wind speeds. More sensitive wind speed sensors available at that time were prone to icing and physical damage from high wind speeds. The meteorological instrumentation installed after July 1982 meets the accuracy requirements outlined in Section C.4 of Proposed Revision 1 to RG 1.23 (September 1980). The operational meteorological instrumentation system accuracies are listed in Table 2.3-5A.
REGULATORY GUIDE 1.24, REVISION 0 (MARCH 1972) - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF PRESSURIZED WATER REACTOR RADIOACTIVE GAS STORAGE TANK FAILURE Position RG 1.24 applies to PWR plants and, therefore, is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.25, REVISION 0 (MARCH 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 FSAR Section 15.7.4.5 Position Evaluation of the radiological consequences of a fuel handling accident is based on RG 1.183; therefore, this regulatory guide is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.26, REVISION 3 (FEBRUARY 1976) - QUALITY GROUP CLASSIFICATION AND STANDARDS FOR WATER-, STEAM-, AND RADIOACTIVE WASTE-CONTAINING COMPONENTS OF NUCLEAR POWER PLANTS FSAR Sections 3.2, 5.4.8.1, 9.2.2, 9.4.4, 9.5.6, 9.5.7, and 9.5.8 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Tables 3.2-1 and 3.2-2.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.27, REVISION 2 (JANUARY 1976) - ULTIMATE HEAT SINK FOR NUCLEAR POWER PLANTS

FSAR Section 9.2.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The Unit 2 ultimate heat sink design was reviewed and approved by the NRC (then the AEC) during the PSAR review. Since that time, the circulating water system design was revised to incorporate a natural-draft cooling tower, and modifications were made to the service water system which were later approved by the NRC.

REGULATORY GUIDE 1.28, REVISION 2 (FEBRUARY 1979) - QUALITY ASSURANCE PROGRAM REQUIREMENTS (DESIGN AND CONSTRUCTION)

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

REGULATORY GUIDE 1.29, REVISION 3 (SEPTEMBER 1978) - SEISMIC DESIGN CLASSIFICATION

FSAR Sections 3.2.1, 5.4.8.1, 7.1.2.3, 8.3.1.2, 9.2.2, 9.4.4, 9.5.6, 9.5.7, 9.5.8, and 10.3.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Tables 3.2-1 and 3.2-2.

REGULATORY GUIDE 1.30, REVISION 0 (AUGUST 1972) - QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRIC EQUIPMENT

FSAR Sections 3.11 and 7.2, Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The Unit 2 Quality Assurance Program complies with RG 1.30 as described in Appendix VII of the Quality Assurance Manual for the project during construction. Unit 2 also complies with this regulatory guide as described in Chapter 17 of the FSAR.

RG 1.30 Revision 0 endorses IEEE-336-1971. Unit 2 Specification E061A, Electrical Installation, invokes IEEE-336-1977, which is more conservative than IEEE-336-1971.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.30, REVISION 0 (AUGUST 1972) (cont'd.)

Section 3 of IEEE-336 addresses the requirements for preinstallation verification of material and equipment. It also states that "it is not intended to duplicate inspections but rather to verify that items are in satisfactory condition for installation." Preinstallation verification includes the following:

1. Identification of materials and equipment.

2. Availability of procedures, instruction manuals, and special work instructions.

3. Review of records of storage and preventive maintenance measures.

4. Visual examination of materials and equipment to ensure physical integrity.

All these required verifications are addressed by the SWEC QA program for receipt, storage, and preventive maintenance inspections. These inspections meet the intent of IEEE-336, Section 3; therefore, additional preinstallation verification is not done for the following components and materials (all equipment, however, is subject to preinstallation verification):

1. Balance-of-plant electrical components and materials such as terminal blocks, fuses, connectors, lugs, mounting hardware, etc.

2. PGCC electrical components and materials that are shipped separately from the main panels by GE, e.g., relays, meters, switches, connectors, lugs, mounting hardware, etc.

The above components and materials are subject to in-process installation inspection and final installation inspections.

REGULATORY GUIDE 1.31, REVISION 3 (APRIL 1978) - CONTROL OF FERRITE CONTENT IN STAINLESS STEEL WELD METAL

FSAR Sections 4.5.1.2, 4.5.2.4, and 5.2.3.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below and in Section 5.2.3.4.

Procurement and erection specifications referencing ASME Section III include the requirements as delineated in RG 1.31 Revision 3.

As an alternative method of conformance, specifications for which all work has been essentially completed or is at a stage where cost of alteration would be prohibitive require compliance with the Interim NRC Position (BTP MTEB 5-1) on RG 1.31 Revision 1, except for:

1. Welding of austenitic stainless steel castings that contain a minimum of 5 percent delta ferrite.

2. Full penetration welds of 1/4-in thickness or less.

3. Welds in pipe of 2-in nominal diameter or less.

4. Welds made between other than austenitic stainless steel to austenitic stainless steel.

5. Fillet welds having a throat dimension of 3/8 in or less.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.32, REVISION 2 (FEBRUARY 1977) - CRITERIA FOR SAFETY-RELATED ELECTRIC POWER SYSTEMS FOR NUCLEAR POWER PLANTS

FSAR Sections 8.2.2, 8.3.1.2, and 8.3.2.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below and in Section 8.3.1.

Conformance with this regulatory guide is ensured through the criteria used in the design of the offsite and the safety-related onsite power systems and in sizing the battery chargers.

REGULATORY GUIDE 1.33, REVISION 2 (FEBRUARY 1978) - QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION)

FSAR Section Chapter 17

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.34 (DECEMBER 28, 1972) - CONTROL OF ELECTROSLAG WELD PROPERTIES

FSAR Sections 5.2.3.3, 5.2.3.4, and 5.3.1.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

Purchase and/or erection specifications include the requirements as delineated in the guide. Presently, no electroslag welding is anticipated for Unit 2 safety-related components.

REGULATORY GUIDE 1.35, REVISION 2 (JANUARY 1976) - IN-SERVICE INSPECTION OF UNGROUTED TENDONS IN PRESTRESSED CONCRETE CONTAINMENT STRUCTURES

Position This regulatory guide is not applicable to Unit 2.

REGULATORY GUIDE 1.36, REVISION 0 (FEBRUARY 1973) - NONMETALLIC THERMAL INSULATION FOR AUSTENITIC STAINLESS STEEL

FSAR Sections 4.5.2.4, 5.2.3.2, and 6.1.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below and in Section 5.2.3.2.

Nonmetallic thermal insulation for austenitic stainless steel, including filler material for encapsulated insulation, complies with RG 1.36, issued February 23, 1973, with the exception of packaging and shipping requirements of Paragraph C.1 of this guide. In lieu of controlled packaging and shipping, receipt inspection and tests are required by specification. This consists of visual inspection for physical or water damage to all cartons. Damaged cartons are segregated. The potentially contaminated insulation is not accepted unless randomly selected samples from each carton are shown to be acceptable after being resubjected to the production test outlined in RG 1.36.

Purchase and/or erection specifications include the requirements as delineated above. No nonmetallic insulation will be in direct contact with safety-related austenitic stainless steel fluid systems within the primary containment on the Unit 2 project.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.37, REVISION 0 (MARCH 16, 1973) - QUALITY ASSURANCE REQUIREMENTS FOR CLEANING OF FLUID SYSTEMS AND ASSOCIATED COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS

FSAR Sections 4.5.1.4, 4.5.2.4, 6.1.1, 17.2

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

1. Paragraph C.3 The water quality for final flushes of fluid systems and associated components is at least equivalent to the quality of the operating system water, except for the oxygen content.

2. Paragraph C.4 Expendable materials, i.e., inks and related products, temperature indicating sticks, tapes, gummed labels, wrapping materials (other than polyethylene), water-soluble dam materials, lubricants, NDT penetrant materials, and couplants that contact stainless steel or nickel alloy surfaces are in accordance with the Unit 2 Position for RG 1.38 Revision 2.

3. Due to seasonal conditions, freshwater from Lake Ontario will have an allowable upper pH limit of 8.5.

4. Upgraded piping systems and components constructed of carbon steel materials will meet Class B cleanness requirements except for final flushing/cleaning which may exhibit rust staining in accordance with Class C cleanness requirements.

The quality assurance requirements of RG 1.37 have been addressed in Appendix VII of the Quality Assurance Program Manual and Section 17 for the Unit 2 project.

Erection specifications and procedures for Category I fluid systems and associated components include the requirements of the guide as delineated above.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

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

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

SWEC and Unit 2 QA program satisfies the QA requirements of RG 1.38 (Unit 2 QA Program Manual Appendix VII and Section 17).

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.39, REVISION 2 (SEPTEMBER 1977) - HOUSEKEEPING REQUIREMENTS FOR WATER-COOLED NUCLEAR POWER PLANTS

FSAR Section Chapter 17

Position* The Unit 2 project complies with the requirements of the Regulatory Position (Paragraph C) of this guide.

Erection and installation specifications establish the requirements and the QA provisions to ensure compliance with this guide. Additionally, the requirements are implemented by site administrative procedures.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

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

FSAR Sections 3.11.2 and 7.1.2.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The Unit 2 design does not include any Class 1E, continuous-duty motors inside the primary containment.

REGULATORY GUIDE 1.41 (MARCH 1973) - PREOPERATIONAL TESTING OF REDUNDANT ONSITE ELECTRICAL POWER SYSTEMS TO VERIFY PROPER LOAD GROUP ASSIGNMENTS

FSAR Section Chapter 14

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The requirements of this guide will be implemented through the preoperational test program.

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

Position This regulatory guide was withdrawn on March 18, 1976, by the NRC. Refer to the position statement for RG 1.111.

REGULATORY GUIDE 1.43 (MAY 1973) - CONTROL OF STAINLESS STEEL CLADDING OF LOW-ALLOY STEEL COMPONENTS

FSAR Sections 5.2.3.3, 5.3.1.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-1
(Sheet 14 of 49)

CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.44, REVISION 0 (MAY 1973) - CONTROL OF THE USE OF SENSITIZED STAINLESS STEEL

FSAR Sections 4.5.2.4, 5.2.3.4, and 6.1.1.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) through the alternate approaches listed below:

BOP

1. Paragraph C.4 When components whose normal operating temperature is in excess of 200°F are subjected to welding after solution heat treating, the material is low carbon grades, or alternatively, the welds are resolution annealed. The only exception is in the inlet fitting in the SLCS explosive valve, which is Type 304 stainless steel.

2. Paragraph C.6 Also, materials that contain more than 0.03 percent carbon and have a normal operating temperature in excess of 200°F will be subjected to an intergranular corrosion test of the heat-affected zone (HAZ). The ASTM A708 standard may be used in lieu of the A262 standard to perform the HAZ intergranular corrosion test, except that the radius of the bend specimen is as specified in ASME Section IX, with the weld-base metal interface at the centerline of the bend.

3. Requirements for maintaining cleanliness, solution annealing, sensitization testing, resolution annealing, and the use of low carbon grades of material in accordance with the guide and the modifications set forth above will be identified in the specifications and procedures.

NSSS

All wrought austenitic stainless steel was purchased in the solution heat-treated condition. Heating above 800°F was prohibited (except for welding) unless the stainless steel was subsequently solution annealed. For Type 304 steel with carbon content in excess of 0.035 percent carbon, purchase specifications restricted the maximum weld heat input to 110,000 Joules/in, and the weld interpass temperature to 350°F maximum. Welding was performed in accordance with Section IX of the ASME Boiler and Pressure Vessel Code. These controls were employed to avoid severe sensitization and to comply with the intent of RG 1.44.

REGULATORY GUIDE 1.45 (MAY 1973) - REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

FSAR Sections 5.2.5.1, 5.2.5.9, and 11.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below and Section 5.2.5.9.

The interpretation given to Regulatory Position C.5 for the sensitivity and response time of each leakage detection system is consistent with equipment capabilities available in the industry.

REGULATORY GUIDE 1.46 (MAY 1973) - PROTECTION AGAINST PIPE WHIP INSIDE CONTAINMENT

FSAR Sections 3.6A.2, 3.6B.2, and 9.2.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described in Sections 3.6A.2 and 3.6B.2, with exceptions as permitted by NRC Generic Letter 87-11, dated June 19, 1987.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.47, REVISION 0 (MAY 1973) - BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS

FSAR Sections 7.1.2, 7.4.2, 7.6.2, and 8.1.7

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

All systems that initiate reactor trip or respond to reactor accidents, such as the core standby cooling system, and the containment isolation system, are designed to conform to this position.

REGULATORY GUIDE 1.48 (MAY 1973) - DESIGN LIMITS AND LOADING COMBINATIONS FOR SEISMIC CATEGORY I FLUID SYSTEM COMPONENTS

FSAR Sections 3.9A.3.1, 3.9B.3, and Table 3.9B-3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

BOP

Complies with the Regulatory Position of this guide.

NSSS

Complies through the alternate approach described in Table 3.9B-3.

REGULATORY GUIDE 1.49, REVISION 1 (DECEMBER 1973) - POWER LEVELS OF NUCLEAR POWER PLANTS

FSAR Sections 5.2.2, 15.0.3, Appendix A

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide for overpressure and transient analyses which do not impact the minimum critical power ratio (MCPR). These analyses will be performed at 102% of core power level.

Alternate Position For pressurization events that could establish the operating limit MCPR, the Unit 2 project will implement an alternate assessment to Regulatory Positions C.2 and C.3. These events will be analyzed assuming a core power level of 100 percent of nuclear boiler rated power. This alternate assessment will be used when the GEMINI methodology of the computer code ODYN is used, as approved by the NRC (reference letter from G. C. Lainas (NRC) to J. S. Charnley (GE), "Acceptance for Referencing of Licensing Topical Report NEDE-24011-P-A, Supplement to Amendment 11," dated March 22, 1986).

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.50, REVISION 0 (MAY 1973) - CONTROL OF PREHEAT TEMPERATURE FOR WELDING OF LOW-ALLOY STEEL

FSAR Sections 5.2.3.3 and 6.1.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below:

BOP

1. In cases where it is impractical to maintain preheat until a postweld heat treatment has been performed, a temperature of 300°F or the applicable preheat temperature (whichever is higher) will be maintained for 2 hr/in of thickness in lieu of Paragraph C.2.

2. The project interprets "low-alloy steels" to include those steels listed as low-alloy steels in mandatory Appendix I to ASME Section III.

3. Paragraph C.1.a of the regulatory guide requires that a minimum preheat be specified in the procedure qualification, while none is required by ASME Section III. The project therefore specifies the recommended preheats of nonmandatory Appendix D to ASME Section III.

NSSS

1. The use of low-alloy steel is restricted to the reactor pressure vessel. Other ferritic components in the RCPB are fabricated from carbon steel materials.

2. Preheat temperatures employed for welding of low-alloy steel meet or exceed the recommendations of ASME Section III, Subsection NA. Components were either held for an extended time at preheat temperature to assure removal of hydrogen, or preheat was maintained until postweld heat treatment. The minimum preheat and maximum interpass temperatures were specified and monitored.

3. All pressure-retaining welds were nondestructively examined by radiographic methods. In addition, a supplemental ultrasonic examination was performed.

REGULATORY GUIDE 1.51 (MAY 1973) - IN-SERVICE INSPECTION OF ASME CODE CLASS 2 AND 3 NUCLEAR POWER PLANT COMPONENTS

Position This regulatory guide was withdrawn by the NRC on July 21, 1981.

REGULATORY GUIDE 1.52, REVISION 2 (MARCH 1978) - DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR ENGINEERED SAFETY-FEATURE ATMOSPHERE CLEANUP SYSTEM AIR FILTRATION AND ADSORPTION UNIT OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

FSAR Sections 6.5.1 and 9.4.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below:

1. Paragraph C.2.a Demisters will be provided only where entrained water droplets could be present. The control building supply air system special filter train (Section 9.4.1) does not require a demister because:

   a. Air entering the filter train is a mixture of recirculated and outdoor air, with sufficient physical separation between the outdoor air louver and filter train to prevent moisture carryover.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.52, REVISION 2 (MARCH 1978) (cont'd.)

b. The entering air side of the filter train is provided with an electric heating coil.

2. Paragraph C.2.d Filter mounting frames and ducts located outside the containment are not designed to withstand DBA pressure surges.

3. Paragraph C.2.h The following exceptions are taken to the requirement that "all instrumentation and equipment controls should be designed to IEEE-279-1971":

a. All instruments and equipment controls that sense or process one or more variables and that act to accomplish the protective function are designed in accordance with IEEE-279. These include sensors, signal conditioners, logic, and actuation device control circuitry. (The protective function with which the subject guide is concerned is atmospheric cleanup to mitigate accident doses.)

b. In addition, a very limited class of analog indicators may be designed in accordance with selected applicable paragraphs of IEEE-279. The basis for selecting specific indicators to be so designed is their significance to safety. All paragraphs of IEEE-279 are applicable, except 4.12, 4.13, 4.15, 4.16, and 4.17. For this limited class of indicators, redundant analog channels are provided, one of which is recorded. The systems are designed to operate before and after, but not necessarily during, a SSE.

c. Annunciator functions are incorporated into overall system design. Annunciators for the ESF filter systems (Sections 6.5.1 and 9.4.1) are not safety related; therefore, they are not designed in accordance with IEEE-279.

4. Paragraph C.2.j ESF atmosphere cleanup systems are designed to be removed as a minimum number of segmented sections. Individual filter components will be removed prior to cutting the housing into segmented sections.

5. Paragraph C.2.l ESF atmospheric cleanup filter housing will be designed and tested in accordance with the requirement of this paragraph. Exception is taken to the leak testing of ductwork, specifically to Section 4.12 of ANSI-N509-1980, for the two ESF atmospheric cleanup systems as follows:

Control Room Filtration Units

HVAC systems (i.e., ductwork, dampers, fans, etc.) within the control room pressure boundary (El 288'-6" and 306'-0" of the control building) will be leak tested to minimize air leakage to a reasonably achievable level. Air cleaning effectiveness, duct and housing quality requirements, and health physics requirements leak rates are not applicable to HVAC systems within this pressure boundary.

Elevations 288'-6" and 306'-0" of the control building are maintained at a positive pressure relative to their surroundings, thus precluding infiltration of potentially-contaminated air. Air in the suction side of the filtration unit fan is at a negative pressure relative to the pressure boundary, thus ensuring in-leakage and filtration of air. Air leaving the filtration units is clean and ultimately will be discharged into the pressure boundary environment. Thus, leakage of air from ductwork, dampers, fans, etc., downstream of the filters will be clean air and is not of concern.

The control room ventilation system will satisfy the intent of air-cleaning effectiveness, duct and housing quality, and health physics requirements, by verifying through tests that the airflows are balanced, positive pressure is achieved, and filter effectiveness is maintained.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.52, REVISION 2 (MARCH 1978) (cont'd.)

Standby Gas Treatment System (SGTS)

The SGTS consists of filter trains, fans, piping, and valves. ASME III piping and valves are used in this system in lieu of ductwork and dampers. A portion of the fan discharge section is through a concrete tunnel that travels underground to the main stack. The major portion of the system (i.e., filter trains, fans, piping, and valves) is located in a clean interspace (standby gas treatment building).

Air-cleaning effectiveness, duct (pipe) and housing quality, and health physics requirement leak rates will be used for all pipe under positive pressure that discharges into the plant stack.

Air-cleaning effectiveness, duct (pipe) and housing quality, and health physics requirement leak rates are not applicable to the suction side of the filtration unit fans since air in the suction side is at a negative pressure relative to the surroundings, thus ensuring in-leakage and filtration of air.

6. Paragraph C.3.d Deleted.

7. Paragraph C.3.e Filter and adsorber mounting frames are constructed and designed in accordance with the recommendations of Section 4.3 of ERDA 76-21, except for the frame tolerance guidelines in Table 4.2. The tolerances selected for HEPA and adsorber mountings are sufficient to satisfy the bank leak test criteria of Paragraphs C.5.c and C.5.d of RG 1.52 Revision 2.

8. Paragraph C.3.h Exception is taken to the recommendations of Section 4.5.8 of ERDA 76-21 relative to drain sizes and arrangement. Manual valves, in addition to water seals and traps, will be provided to control the discharge of the fire sprinkler flow (see Figure 1.8-1).

9. Paragraph C.3.i Exception is taken to the requirement that the absorption unit should be designed for a maximum loading of 2.5 mg of total iodine per gram of activated carbon. RG 1.52 Revision 1 states that "the absorption unit should have the capacity of loading 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon." The absorption unit provided has a loading capacity of 10.0 mg of total iodine per gram of activated carbon.

10. Paragraph C.3.k Exception is taken to the requirement for humidity control to below 70 percent relative humidity for low flow air bleed cooling.

    Each filter train is physically separated, and the common connection between the filter trains is provided with redundant high temperature sensors and isolation valves to maintain equipment integrity in one filter train upon detection of high temperature.

11. Paragraph C.3.l System resistances will be determined in accordance with Section 5.7.1 of ANSI N509-1976 except that fan inlet and outlet losses will not be calculated in accordance with AMCA 201, but will be estimated and documented accordingly.

    Exception is taken to balancing techniques defined in Section 5.7.3 of ANSI N509-1976. The acceptable amplitude of vibration, peak to peak, in any plane measured on the shaft adjacent to the bearings, corresponds to a vibration velocity of 0.1 in/sec at the rated speed using the displacement values given in AMCA Publication 801. The displacement criteria using maximum vibration velocity method in accordance with ANSI N509-1976 are not required by the later ANSI N509-1980. The acceptable criteria of the later standard are similar to that of AMCA Publication 801. Documentation will not be furnished in accordance with Section 5.7.5 where AMCA certification ratings are submitted.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.52, REVISION 2 (MARCH 1978) (cont'd.)

12. Paragraph C.3.n Exception is taken to Section 5.10.3.5 of ANSI N509-1976; ductwork which consists of sheet sections and is considered as a complete structure, will have a resonant frequency above 25 Hz.

13. Paragraph C.3.p Exception is taken to the provisions in Section 5.9 of ANSI N509-1976 of designing dampers to ANSI B31.1 and to using butterfly valves. Class B dampers may be designed and tested to meet the verification of strength and leak-tightness necessary for use in a contaminated air stream. (NOTE: This exception does not pertain to containment penetrations.)

    In addition, exceptions are taken to the following:

    Minimum diameter of damper shaft length 24 in and under will be 1/2 in; and 3/4 in for shafts between 25 and 48 in.

14. Paragraph C.4.a Exception is taken to full compliance with Section 2.3.8 of ERDA 76-21; i.e., SWEC does not use any communication system, floor drains are as noted in Paragraph C.3.h above, decontamination areas and showers are not "nearby," filters are not used at duct inlets, and duct inspection hatches are not provided.

15. Paragraph C.4.d ESF atmosphere cleanup systems are tested once per 31 days. Exception is taken as follows:

    Control Room Filtration Units ESF atmosphere cleanup system for the control room is tested once per 31 days for at least 1 hr.

16. Paragraph C.5.c, C.5.d, and C.6.a Periodic testing will be conducted in accordance with the Technical Specifications.

REGULATORY GUIDE 1.53, REVISION 0 (JUNE 1973) - APPLICATION OF THE SINGLE FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS

FSAR Sections 7.2.2, 7.3.2, 7.6.2, and 9.2.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

All systems that initiate reactor trip or respond to reactor accidents, such as containment isolation system and core standby cooling systems, will be designed in conformance with this guide.

REGULATORY GUIDE 1.54 (JUNE 1973) - QUALITY ASSURANCE REQUIREMENTS FOR PROTECTIVE COATINGS APPLIED TO WATER-COOLED NUCLEAR POWER PLANTS

FSAR Sections 6.1.2, Chapter 17

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

In lieu of the inspection in accordance with ANSI N5.9-1967, as defined in Section 6.2.4 of ANSI N101.4-1972, inspection will be in accordance with ANSI N512-1974, Section 10, Inspection for Shop and Field Work. Also, the documentation of prime coating of structural shapes used in pipe, conduit, and instrumentation support fabrication meets all aspects of the regulatory guide, except that the exact batch number of qualified paint used on these items may not be traceable to the specific support.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.54 (JUNE 1973) (cont'd.)

NSSS

ANSI N101.4-1972, in conjunction with ANSI N45.2-1971, provides an adequate basis for complying with quality assurance requirements for protective coatings applied to ferritic steels, aluminum, stainless steel, galvanized steel, concrete, or masonry.

Most NSSS equipment for this plant is coated with a prime coat of inorganic zinc. This coating was one of the first to be qualified under ANSI N101.2 for DBA, radiation, etc., in nuclear applications. Equipment specifications in place at the time of ordering equipment for this plant specified inorganic zinc.

There is a minimum amount of unqualified paint which is addressed in FSAR Section 6.1.2 and Table 6.1-3. Equipment tightly covered with thermal insulation is not included in this total since potential paint debris could not escape to the suppression pool during a LOCA.

The quality assurance requirements in the regulatory guide were not imposed on painted material and paint application since most NSSS equipment was ordered prior to issuance of the guide.

REGULATORY GUIDE 1.55 (JUNE 1973)* - CONCRETE PLACEMENT IN CATEGORY I STRUCTURES

FSAR Sections 3.8.3, 3.8.4, 3.8.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

Conformance to this regulatory guide is ensured through purchase specifications.

* This regulatory guide was withdrawn on July 8, 1981, by the NRC. It is superseded by RG 1.136 Revision 2 (June 1981).

REGULATORY GUIDE 1.56, REVISION 1 (JULY 1978) (FOR COMMENT) - MAINTENANCE OF WATER PURITY IN BOILING WATER REACTORS

FSAR Section 5.2.3.2, Technical Specifications

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The design of the Unit 2 condensate demineralizer system is in conformance with the regulatory guide.

The Unit 2 Technical Requirements Manual will describe the operating requirements to conform with this guide.

REGULATORY GUIDE 1.57, REVISION 0 (JUNE 1973) - DESIGN LIMITS AND LOADING COMBINATIONS FOR METAL PRIMARY REACTOR CONTAINMENT SYSTEM COMPONENTS

Position RG 1.57 applies to power plants with metal primary containments and, therefore, is not applicable to the Unit 2 project.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.58, REVISION 1 (SEPTEMBER 1980) - QUALIFICATION OF NUCLEAR POWER PLANT INSPECTION, EXAMINATION, AND TESTING PERSONNEL

FSAR Section 14.2

Position During the design and construction phase, startup and test personnel involved in testing met the requirements of RG 1.58 and ANSI N45.2.6-1978, with exceptions as discussed in Chapter 14.

Unit 2 plant personnel met the requirements of this regulatory guide as discussed in Chapter 13.

GE startup operations personnel supporting the startup test phase met the requirements of this regulatory guide as discussed in Table 14.2-403.

During the operations phase, the qualification of nuclear power plant inspection, examination, and testing personnel is stated in the QA Program requirements and is satisfied as specified in the Quality Assurance Program Topical Report (QATR).

REGULATORY GUIDE 1.59, REVISION 2 (AUGUST 1977) - DESIGN BASIS FLOODS FOR NUCLEAR POWER PLANTS

FSAR Sections 2.4.5, 2.4.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, with the following limitation:

No commitments for compliance are made or implied for the "to be issued" appendices.

The Unit 2 site has hardened protection from flooding by use of a lakefront revetment ditch.

Evaluation of the conditions (Paragraph C.1) resulting in the worst site-related flood probable at the Unit 2 site has been made in conformance with ANSI N170-1976/ANS 2.8. The combined events considered were:

1. Probable maximum surge and seiche with wind wave action and maximum controlled lake level.

2. Probable maximum precipitation and historical maximum lake level.

3. Probable maximum lake level and historical maximum precipitation.

The analysis showed that Unit 2 is designed to withstand these combined events with no safety impact.

REGULATORY GUIDE 1.60, REVISION 1 (DECEMBER 1973) - DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS

FSAR Sections 3.7A, 3.7B

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide as discussed below and in Sections 3.7A and 3.7B.

The design response spectra has been used to generate the seismic data sheets for equipment loadings, for systems and component analysis, and for the structural responses of the various buildings.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.61, REVISION 1 (MARCH 2007) - DAMPING VALUES FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS

FSAR Sections 3.7A, 3.7B.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The damping values used for the design of Category I structures, systems, and components for Unit 2 meet the requirements of this guide.

The damping values in the guide are used in conjunction with RG 1.60 for fully defining seismic design criteria.

REGULATORY GUIDE 1.62, REVISION 0 (OCTOBER 1973) - MANUAL INITIATION OF PROTECTIVE ACTIONS

FSAR Sections 7.1.2, 7.2.2, 7.3.2, 7.4.2, 7.6.2, 8.1.3, 8.3.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

All systems that initiate reactor trip or respond to reactor accidents, such as core standby cooling systems and the containment isolation system, are designed to conform to this guide.

REGULATORY GUIDE 1.63, REVISION 2 (JULY 1978) - ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR WATER-COOLED NUCLEAR POWER PLANTS

FSAR Sections 3.11, 7.1.2, 8.3.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, except as noted as follows:

In lieu of the installation, inspection, and testing requirements in Section 8.1 of IEEE-317-1976, the electrical penetrations are installed, inspected, and tested in accordance with SWEC quality standards, QA and EA procedures relating to Category I installation of safety-related equipment, which conform to 10CFR50 Appendix B. It may be noted that the penetrations are attached (bolted) to the containment liner, which is a noncode-stamped component.

REGULATORY GUIDE 1.64, REVISION 2 (JUNE 1976) - QUALITY ASSURANCE REQUIREMENTS FOR THE DESIGN OF NUCLEAR POWER PLANTS

FSAR Section Chapter 17

Position RG 1.64 Revision 2, dated June 1976, is not applicable to Unit 2. The regulatory guide revision specifies that the revision is applicable to evaluation of submittals in connection with construction permit application docketed after July 15, 1975. The Unit 2 construction permit application was docketed on June 15, 1972.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

<u>REGULATORY GUIDE 1.65, REVISION 0 (OCTOBER 1973)</u> - MATERIALS AND INSPECTIONS FOR REACTOR VESSEL CLOSURE STUDS <u>FSAR Sections</u> 5.3.1.7, Chapter 14 <u>Position</u> The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below. The reactor pressure vessel closure studs are SA-540 Grade B23 or 24 (AISI 4340) and have a maximum ultimate tensile strength of 169 ksi. Additionally, GE has specified the bolting material must have Charpy V-notch impact properties of 45 ft-lbs minimum with 25 mil lateral expansion. NDE before and after threading is specified to be in accordance with Subsubarticle NB-2580, ASME Section III, which complies with Regulatory Position C.2. Subsequent to fabrication, the studs are manganese phosphate coated and are lubricated with a graphite/alcohol or a nickel powder base lubricant. In relationship to Regulatory Position C.2.b, the bolting materials were ultrasonically examined after final heat treatment and prior to threading, as specified. The specified requirement for examination according to SA-388 was complied with. The procedures approved for use in practice were judged to insure comparable material quality and, moreover, were considered adequate on the basis of compliance with the applicable requirements of ASME Code, Paragraph NB-2583. Additionally, straight beam examination was performed on 100 percent of cylindrical surfaces, and from both ends of each stud using a 3/4 maximum diameter transducer. In addition to the code-required notch, the reference standard for the radial scan contained a 1/2-in diameter flat bottom hole with a depth of 10 percent of the thickness, and the end scan standard contained a 1/4-in diameter flat bottom hole 1/2 in deep. Also, angle beam examination was performed on the outer cylindrical surface in both a flat and circumferential direction. Surface examinations were performed on the studs and nuts after final heat treatment and threading, as specified in the guide, in accordance with Paragraph NB-2583 of the applicable ASME Code. Radial scan calibration is based on a 1/2-in (12.7-mm) diameter flat bottom hold of a depth equal to 10 percent of the material thickness. Angle beam examination is performed on the outer cylindrical surface of nuts and washer in accordance with ASME SA-388 in both axial and circumferential directions. Any indication greater than the indication from the applicable calibration feature is unacceptable. A distance-amplitude correction curve in accordance with paragraph NB-2585 is used for the longitudinal wave examination. In relationship to Regulatory Position C.3, GE practice allows exposure of stud bolting surfaces to high purity fill water; nuts and washers are dry-stored during refueling. An in-service inspection is described in Section 14 of the FSAR.
<u>REGULATORY GUIDE 1.66, REVISION 0 (OCTOBER 1973)</u> - NONDESTRUCTIVE EXAMINATION OF TUBULAR PRODUCTS <u>Position</u> This regulatory guide was withdrawn by the NRC on September 28, 1977.
<u>REGULATORY GUIDE 1.67, REVISION 0 (OCTOBER 1973)</u> - INSTALLATION OF OVERPRESSURE PROTECTIVE DEVICES <u>FSAR Section</u> 3.9A.3 <u>Position</u> The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide. For ASME Code Class 1, 2, and 3 piping analysis, transient analysis and dynamic loading are considered in the stress allowable limits.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.68, REVISION 2 (AUGUST 1978) - INITIAL TEST PROGRAMS FOR WATER-COOLED REACTOR POWER PLANTS

FSAR Section Chapter 14

Position Unit 2 complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The format of the test procedures may differ from that described in Appendix C of this guide. However, all required elements are included. A detailed test program is provided in Chapter 14 of the FSAR.

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

FSAR Section Chapter 14

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The condensate and feedwater systems will be preoperationally tested in accordance with RG 1.68. The reactor level control components will be calibrated and functionally checked to the maximum extent practical prior to fuel loading. During the startup phase, reactor level control will be dynamically tested at various power levels.

REGULATORY GUIDE 1.68.2, REVISION 1 (JULY 1978) - INITIAL STARTUP TEST PROGRAM TO DEMONSTRATE REMOTE SHUTDOWN CAPABILITY FOR WATER-COOLED NUCLEAR POWER PLANTS

FSAR Section Chapter 14

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.68.3, REVISION 0 (APRIL 1982) - PREOPERATIONAL TESTING OF INSTRUMENT AND CONTROL AIR SYSTEMS

FSAR Section Chapter 14

Position The Unit 2 project complies with the intent of this regulatory guide by taking an alternative approach.

Unit 2 follows the guidelines in RG 1.80.

The Unit 2 instrument air system is not nuclear safety related. Portions of RG 1.68.3 are addressed since they are implemented by RG 1.68. Otherwise, RG 1.68.3 is not applicable to Unit 2 since its instrument air system is not safety related.

The implementing activities described in Positions C.1, 2, 3, 4, 5, 6, 9, and 10 of RG 1.68.3 are typical for the testing of instrument air systems. The project complies with the requirements of these regulatory positions.

Regulatory Positions C.8 and 11 of RG 1.68.3 are applicable to projects with a nuclear safety-related instrument air system; therefore, these positions are not applicable to Unit 2.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.68.3, REVISION 0 (APRIL 1982) (cont'd.)

The instrument air system does interface with components that are part of nuclear safety-related systems. Tests will be conducted on such components in accordance with RG 1.68.3 to demonstrate that these components function as designed upon loss of their nonnuclear safety-related air supply.

To verify that loss of instrument air will not affect any safety-related system from performing its designated function, a loss-of-air-supply test will be performed on those portions of the instrument air system which interface with nuclear safety-related systems. This test will demonstrate that air-controlled components supplied directly from the instrument air system will assume their design fail-safe positions upon loss of air supply. This test will also demonstrate that those components provided with safety-related air accumulators will properly isolate from the instrument air supply system while retaining sufficient stored air capacity to perform their designated safety functions.

Testing will include a verification that no crossties between service and instrument control air degrade the system. Sudden pressure drops in the entire system are not feasible because the design incorporates excess flow checks. However, all excess flow check valves will be verified to be operable.

REGULATORY GUIDE 1.69, REVISION 0 (DECEMBER 1983) - CONCRETE RADIATION SHIELDS FOR NUCLEAR POWER PLANTS

FSAR Sections 3.8.4, 12.3

Position The Unit 2 project complies with the Regulatory Position (Section C) of this guide through the alternate approaches described below.

Coatings for concrete surfaces comply with the requirements of Paragraph C.3.g of RG 8.8 and ANSI N5.12, Protective Coatings (Paints) for the Nuclear Industry.

1. The increase in allowable stresses for earthquake forces normally permitted by ACI 318 will not be used.

2. Finishing and patching of concrete surfaces after removal of forms will conform to Chapter 9 of ACI 301 instead of to Section 8.7.5 of ANSI N101.6. It is not necessary or customary to complete this work within 96 hr after the placing of concrete.

3. Testing of shielding by a point source to determine the adequacy of the shields will not be performed. Radiation levels of the actual radiation sources are monitored on a periodic basis throughout the plant where personnel access is required, including during startup testing when radiation levels are measured throughout the plant for various power levels. Further, the density of the concrete shielding is continuously monitored by the quality control program during construction to ensure the adequacy of the protection.

REGULATORY GUIDE 1.70, REVISION 3 (NOVEMBER 1978) - STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS - LWR EDITION

Position The Unit 2 FSAR has been prepared following the format and content requirements contained in this regulatory guide, except in some cases where the content requirements were described or presented to conform to the Unit 2 established programs. The differences are not considered an exception, as the material is presented in a manner consistent with the intent of this regulatory guide.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.71 (DECEMBER 1973) - WELDER QUALIFICATION FOR AREAS OF LIMITED ACCESSIBILITY

FSAR Sections 4.5.2.4, 5.2.3.3, 5.2.3.4, 6.1.1.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below and Sections 4.5.2 and 5.2.3. Welder qualification for areas of limited accessibility in Section III fabrications complies with RG 1.71 Revision 0 which was issued in December 1973. Paragraph C of the regulatory guide will be implemented as follows:

1. Low-alloy steels and high-alloy steels include steels listed as such in the table in Appendix I of the ASME Section III Code.

2. Applicable weld joint designs include full and partial penetration groove, fillet, and socket welds.

3. Section III applicability includes all subsections of ASME Section III.

4. Limited accessibility will be determined only as it relates to the direction from the joint from which welding is to be performed, not to any direction from the joint. Limited accessibility is defined as:

   a. When the welder cannot see the entire weld joint without visual aid.

   b. When the welder can see the entire weld joint but cannot manipulate his electrode to achieve adequate fusion.

An acceptable alternative to this position is as follows:

In lieu of paragraphs C1 and C2a, all applicable full penetration welds of limited accessibility are volumetrically inspected to the requirements and standards of Section III, Class 1.

REGULATORY GUIDE 1.72, REVISION 2 (NOVEMBER 1978) - SPRAY POND PIPING MADE FROM FIBERGLASS-REINFORCED THERMOSETTING RESIN

Position RG 1.72 applies to power plants with spray ponds and therefore is not applicable to the Unit 2 project.

REGULATORY GUIDE 1.73, REVISION 0 (JANUARY 1974) - QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS

FSAR Sections 3.11, 7.1.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described in Sections 3.11 and 7.1.2.

REGULATORY GUIDE 1.74 (FEBRUARY 1974) - QUALITY ASSURANCE TERMS AND DEFINITIONS

FSAR Section Chapter 17

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.75, REVISION 2 (SEPTEMBER 1978) - PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS

FSAR Sections 7.1.2, 7.6.2, 8.3.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below and in Section 7.6.2 and 8.3.1.

Regulatory Position C.1 states that "interrupting devices actuated only by fault current are not considered to be isolation devices within the context of this document." In the case of control and instrument circuits, a combination of two interrupting devices actuated by fault current have been used to isolate non-Class 1E circuits from Class 1E circuits. Both of these devices are Class 1E, and both of them are coordinated with the main breaker upstream so that a failure of a non-Class 1E device or circuit will not affect any Class 1E device or system. Any circuit breakers associated with this redundant protection will be tested during each refueling outage.

Regulatory Position C.9 requires that cable splices in raceways be prohibited. Splicing in electrical penetrations for termination is considered to be exempt from this requirement. Also, condulets and junction boxes used as a termination point, at the load, are considered to be exempt from this requirement.

Regulatory Position C.10 requires that the cables be marked at 5-ft intervals. This is a typographical error as confirmed by the former Electrical, Instrument and Control Branch Chief of USNRC, T. A. Ippolito, on October 10, 1975, and the NRC Power Systems Branch Section Leader, R. G. FitzPatrick, on October 30, 1980. The correct distance is 15 ft, which has been followed in Unit 2. Additionally, the cable markings are inspected (100 percent) by Field Quality Control during installation. As of June 1984 more than 50 percent of all cables had been pulled and marked at 15-ft intervals. We believe that mixing the marking of the cables is inappropriate and that marking at 15-ft intervals is sufficient to ensure separation of cables.

The minimum separation distance from 600 V or less nonsafety-related conduit to safety-related open cable trays and cable in free air for any service level is 1 in.

All cables used in Unit 2 are flame retardant. The cable trays are not filled above the side rails. The hazard, in this case, is limited to failure or faults internal to the nonsafety cables in rigid steel conduit. Unit 2 has determined by analysis that 1-in separation between the Class 1E cable tray and non-Class 1E conduit provides adequate protection for the Class 1E cables in the open ladder tray in the event of any failure of the non-Class 1E cables in conduit. This has been established by tests with 600 V levels, as explained later in this section.

Aluminum sheath cables (ALS) used for low-energy 120-V ac systems and 8-hr battery-pack lighting systems, are considered enclosed raceways. These cables have flame-retardant cross-linked polyethylene insulation, chlorosulphonated polyethylene jacket, and polypropylene fillers enclosed in a continuous, impervious aluminum sheath which provides adequate protection. As such, the minimum separation between these cables and Class 1E raceways is 1 in.

The minimum separation between any Class 1E raceway and any lighting cord for drops to the lighting fixtures shall be 1 in. These cords are of size 12 AWG and supply 120/208 V ac low energy in low-density applications. As such, 1-in separation provides adequate protection to the Class 1E circuits in the event of a fault in any lighting cord.

IEEE-384-1974, Section 5.1.1.2, allows lesser separation distances than those specified in Sections 5.1.3 and 5.1.4, if established by analysis. Various tests have indicated that the following minimum separation distances between redundant Class 1E cables and raceways, or between Class 1E and non-Class 1E cables and raceways, 600 V level and below, should be adequate to maintain independence of the redundant systems. Unit 2 also has verified these minimum separation distances by plant-specific tests (Wyle Test Report No. 47906-02, Electrical Separation Verification Testing).

REGULATORY GUIDE 1.75, REVISION 2 (SEPTEMBER 1978) (cont'd.)

Cable tray to cable tray	10 in horizontal or 10 in vertical
Cable tray to conduit	1 in
Cable in free air to conduit	1/2 in
Cable in free air to cable in free air	10 in vertical or 10 in horizontal
Cable in free air to cable tray	10 in vertical or 10 in horizontal
Wrapped cable to unwrapped cable	0 in
Conduit to conduit	1/2 in
Class 1E control/instrument cable to non-Class 1E control instrument cable inside control/instrument cabinets	1 in

Where the minimum separation distances specified in Sections 5.1.3 and 5.1.4 of IEEE-384-1974 cannot be maintained due to physical arrangements, the minimum separation distances specified above shall be maintained.

Where the minimum separation distances specified in this section cannot be maintained, enclosed raceways will be used; or a separation barrier will be installed.

A comparison of the Unit 2 design to the criteria contained in RG 1.75 and IEEE-384-1974 is shown in Appendix 7B for instrumentation and control systems within the PGCC and balance of plant.

REGULATORY GUIDE 1.76 (APRIL 1974) - DESIGN BASIS TORNADO FOR NUCLEAR POWER PLANTS

FSAR Section 3.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

All applicable structures, systems, or components important to safety are designed to withstand, or are enclosed in structures that will withstand, the six descriptive parameters given in Table I of this regulatory guide. The parameters of Region 1 are applicable to this facility.

REGULATORY GUIDE 1.77 (MAY 1974) - ASSUMPTIONS USED FOR EVALUATING A CONTROL ROD EJECTION ACCIDENT FOR PWRS

Position RG 1.77 applies to PWR plants and is not applicable to the Unit 2 project.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

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 FSAR Section 6.4.2.3 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 1.79, REVISION 1 (SEPTEMBER 1975) - PREOPERATIONAL TESTING OF EMERGENCY CORE COOLING SYSTEMS FOR PRESSURIZED WATER REACTORS Position RG 1.79 applies to PWR plants and is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.80 (JUNE 1974) - PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS FSAR Section 9.3.1 Position This regulatory guide was withdrawn by the NRC on April 20, 1982. It has been superseded by RG 1.68.3 Revision 0 (April 1982).
REGULATORY GUIDE 1.81, REVISION 1 (JANUARY 1975) - SHARED EMERGENCY AND SHUTDOWN ELECTRIC SYSTEMS FOR MULTI-UNIT NUCLEAR POWER PLANTS Position RG 1.81 applies to multi-unit nuclear power plants and is not applicable to the Unit 2 project because Unit 2 does not share any emergency or shutdown electric systems.
REGULATORY GUIDE 1.82 (JUNE 1974) - SUMPS FOR EMERGENCY CORE COOLING AND CONTAINMENT SPRAY SYSTEMS Position RG 1.82 applies to PWR plants and is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.82, REVISION 2 (MAY 1996) - WATER SOURCES FOR LONG-TERM RECIRCULATION COOLING FOLLOWING A LOSS-OF-COOLANT ACCIDENT Position RG 1.82 Revision 2 applies to the replacement of the ECCS suction strainers as described in USAR Sections 5.4.7.1.1, 6.1.2.2, 6.2.2.2, 6.2.2.3.2, 6.3.2.2, 6.3.2.2.1 and 6.3.2.2.3.
REGULATORY GUIDE 1.83, REVISION 1 (JULY 1975) - IN-SERVICE INSPECTION OF PWR STEAM GENERATOR TUBES Position RG 1.83 applies to PWR plants and is not applicable to the Unit 2 project.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

Regulatory Guide 1.84, Revision 22 (July 1984) - DESIGN AND FABRICATION CODE CASE ACCEPTABILITY - ASME SECTION III DIVISION I

FSAR Section 5.2.1.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

RG 1.84 provides a list of ASME Design and Fabrication Code cases that have been generically approved by the regulatory staff. Code cases on this list may, for design purposes, be used until appropriately annulled. Annulled cases are considered "active" for equipment that has been contractually committed to fabrication prior to the annulment.

The various ASME Code cases that were applied to components in the RCPB are listed in Table 5.2-1. All Safety Class 2 and 3 equipment has been designed to ASME Code or ASME-approved Code cases. This provision, together with the quality control programs, provides adequate safety equipment functional assurances.

REGULATORY GUIDE 1.85, REVISION 22* (JULY 1984) - MATERIALS CODE CASE ACCEPTABILITY - ASME SECTION III DIVISION I

FSAR Section 5.2.1.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

RG 1.85 provides a list of ASME design and fabrication code cases that have been generically approved by the regulatory staff. Code cases on this list may, for design purposes, be used until appropriately annulled. Annulled cases are considered "active" for equipment that has been contractually committed to fabrication prior to the annulment.

The various ASME Code cases that applied to components in the RCPB are listed in Table 5.2-1.

All Safety Class 2 and 3 equipment has been designed to ASME Code or ASME-approved Code cases. This provision, together with the quality control programs, provides adequate safety equipment functional assurances.

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* Later revisions of the guide are used for code cases and revisions not included in Revision 22 as allowed by Table 5.2-1.

REGULATORY GUIDE 1.86, REVISION 0 (JUNE 1974) - TERMINATION OF OPERATING LICENSES FOR NUCLEAR REACTORS

FSAR Section General Application

Position At the termination of operation, Unit 2 will meet the criteria set forth in this regulatory guide and will fully comply with its requirements.

REGULATORY GUIDE 1.87, REVISION 1 (JUNE 1975) - GUIDANCE FOR CONSTRUCTION OF CLASS 1 COMPONENTS IN ELEVATED-TEMPERATURE REACTORS

Position RG 1.87 applies to HTGR plants and is not applicable to the Unit 2 project.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.88, REVISION 2 (OCTOBER 1976) - COLLECTION, STORAGE, AND MAINTENANCE OF NUCLEAR POWER PLANT QUALITY ASSURANCE RECORDS

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, except to change ANSI N45.2.9-1974 Section 5.6, Paragraph 3, to "Two hour minimum rated facility" in accordance with NFPA 232-1980. Implementation is as described below.

Unit 2 quality assurance records (and other required records) are stored in facilities designated as the Permanent Plant File and the Records Acceptance Center. In-process records are stored in controlled Intermediate Storage Facilities. Specific requirements for each include:

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

1. Permanent Plant File Complies to the above paragraph of this position statement.

2. Records Acceptance Center Complies with ANSI N45.2.9-1974 Section 5.3 to provide a mechanism to control records. The storage facility shall meet Section 5.6 except as follows:

   a. Structure has a minimum 2-hr fire rating.

   b. Doors, frames, and hardware have a 2-hr vault door.

   c. Electrical facilities shall be limited to ceiling lights, air-conditioning units, smoke detectors, and alarm circuits.

3. Intermediate Storage Facilities Complies with ANSI N45.2.9-1974 Section 5.3 to provide a mechanism to control records. Each intermediate storage facility shall be evaluated by a Fire Protection Engineer to fulfill NFPA 232-1980 requirements. NOTE: All intermediate storage facilities will be eliminated as contractor work is concluded.

The above controls and facilities are prepared to protect quality assurance records which take their physical form as radiographs, microfilm, and paper.

1. Special handling and environmental storage considerations must be maintained for radiographs.

2. Designated archive (silver halide only) microfilm requires environmental storage considerations.

3. Use of fire-retardant cabinets is applicable to paper storage only.

Technical Justification

ANSI N45.2.9-1974 does not adequately define the storage facilities for in-process quality records or NFPA requirements for fire rating of the facility. NFPA 232-1980, 1-3, emphasizes, "To consult with an experienced and competent Fire Protection Engineer or Records Protection Consultant." This position is based upon his recommendations. The Unit 2 Records Management Plan establishes the program for turnover, collection, review, transfer, receipt, verification, permanent plant file entry, and retention of all Unit 2 records with implementing policy guidelines which specify the facility types.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.89, REVISION 0 (NOVEMBER 1974) - QUALIFICATION OF CLASS 1E EQUIPMENT FOR NUCLEAR POWER PLANTS FSAR Sections 3.11, 7.1.2 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below. BOP Determination of the radiation dose used for qualification of Class 1E plant equipment takes into account design features such as the location of equipment within or outside the containment, fission product cleanup of the containment atmosphere by the containment spray system, local shielding, the time period required for equipment operation, and spatial location. These design features will be applied in a conservative manner to realistically determine the radiation doses to which the devices must be qualified in addition to the other environmental factors. NSSS All environmental and seismic qualification testing of Class 1E equipment within GE's scope of supply was in compliance with IEEE-323-1971 and IEEE-344-1971.
REGULATORY GUIDE 1.90, REVISION 1 (AUGUST 1977) - IN-SERVICE INSPECTION OF PRESTRESSED CONCRETE CONTAINMENT STRUCTURES WITH GROUTED TENDONS Position RG 1.90 applies to power plants with prestressed concrete containments and is not applicable to the Unit 2 project.
REGULATORY GUIDE 1.91, REVISION 1 (FEBRUARY 1978) (FOR COMMENT) - EVALUATION OF EXPLOSIONS POSTULATED TO OCCUR ON TRANSPORTATION ROUTES NEAR NUCLEAR POWER PLANT SITES FSAR Section 2.2.3 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 1.92, REVISION 1 (FEBRUARY 1976) - COMBINING MODAL RESPONSES AND SPATIAL COMPONENTS IN SEISMIC RESPONSE ANALYSIS FSAR Sections 3.7A.3, 3.7B.3 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Section 3.7A.3 and 3.7B.3.
REGULATORY GUIDE 1.93, REVISION 0 (DECEMBER 1974) - AVAILABILITY OF ELECTRIC POWER SOURCES FSAR Section 8.3, Technical Specifications Position Availability requirements for electrical power sources are addressed in the Technical Specifications. Any alternatives to the provisions in the Regulatory Position (Paragraph C) of this guide are submitted to the NRC for review and approval as a license amendment request.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

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

FSAR Sections Chapter 17, Appendix B (QA Topical Report)

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

1. ANSI N45.2.5-1974 Section 5.3 Bolt holes generally will not be burned (oxygen cut). If holes must be burned, the following criteria will be followed: (a) after cutting, the edges of the cut will be ground or reamed back a minimum of 1/32 in, and (b) the final bolt hole dimensions will not exceed those given in the Specification for Structural Joints Using ASTM A325 or A490 bolts.

2. ANSI N45.2.5-1974 Section 5.4 For the Unit 2 project, the criterion established for correct bolt length is one thread extending beyond the face of the nut.

3. ANSI N45.2.5-1974 Section 5.5 All reinforcing bar splices made by arc welding, except those splices welded to metal embedments, will be selected on a random basis for radiography as specified in the Unit 2 PSAR Section 12.6.3, and inspected in accordance with AWS D12.1. Splices welded to metal embedments will be inspected in accordance with AWS 12.1. Additionally, sister splice testing will be done in accordance with Specification No. NMP2-S203C with the same frequency as specified for B-series sister splices when required by the engineers.

4. ANSI N45.2.5-1974 Section 6.2.2 Exceptions regarding mechanical splicing of QA Category I reinforcing bars can be found in Unit 2 Project Position 1.10.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

REGULATORY GUIDE 1.95, REVISION 1 (JANUARY 1977) - PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST AN ACCIDENTAL CHLORINE RELEASE

FSAR Section 6.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.96, REVISION 1 (JUNE 1976) - DESIGN OF MAIN STEAM ISOLATION VALVE LEAKAGE CONTROL SYSTEMS FOR BOILING WATER REACTOR NUCLEAR POWER PLANTS

FSAR Sections 1.2.9.11, 5.4.5, 6.2.3.2.3, 15.6.5

Position MSIV leakage, at the maximum rate allowed by the Technical Specifications, has been included in the secondary containment bypass leakage analysis (Section 6.2.3.2.3) and in the LOCA radiological consequence analysis (Section 15.6.5). These design-basis analyses demonstrate that the calculated exposures are within the criteria of 10CFR50.67 and 10CFR50 Appendix A, General Design Criteria 19.

In addition, a qualitative comparison has been made between Unit 2 and the plant used as the basis for analyses presented in NUREG-1169, "Technical Findings Related to Generic Issue C-8; Boiling Water Reactor Main Steam Isolation Valve Leakage and Leakage Treatment Methods." This comparison demonstrated that the design features of Unit 2 are sufficiently similar to the NUREG-1169 base plant, such that the conclusions of NUREG-1169 are considered directly applicable to Unit 2. NUREG-1169 concluded that the overall risks from the accident sequences in which MSIV leakage could be a significant factor are low without a leakage control system, and alternate fission product handling techniques, which make use of the holdup volume of the main steam lines and condenser, produce significant reductions in offsite dose consequences. It is therefore concluded that a MSIV leakage control system is not required for Unit 2.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.97, REVISION 3 (MAY 1983) - INSTRUMENTATION FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS TO ASSESS PLANT AND ENVIRONS CONDITIONS DURING AND FOLLOWING AN ACCIDENT FSAR Sections 1.10, 7.1.2, 7.5.2.1 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Section 7.5.2.1.
REGULATORY GUIDE 1.98, REVISION 0 (MARCH 1976) (FOR COMMENT) - ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A RADIOACTIVE OFFGAS SYSTEM FAILURE IN A BOILING WATER REACTOR FSAR Section 15.7.1 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 1.99, REVISION 2 (MAY 1988) - EFFECTS OF RESIDUAL ELEMENTS ON PREDICTED RADIATION DAMAGE TO REACTOR VESSEL MATERIALS FSAR Sections 5.3.1, 5.3.2 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Sections 5.3.1 and 5.3.2.
REGULATORY GUIDE 1.100, REVISION 1 (AUGUST 1977) - SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS FSAR Sections 3.10A, 3.10B, 7.1, 8.3 Position The Unit 2 project addresses the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Sections 3.10A and 3.10B.
REGULATORY GUIDE 1.101, REVISION 3 (AUGUST 1992) - EMERGENCY PLANNING FOR NUCLEAR POWER PLANTS FSAR Section Site Emergency Plan Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below. The Emergency Plan has been written to comply with NUREG-0654, Rev. 1, as modified by Supplement 1 for exercise start time. Exception: Exercise frequency permitted by 10CFR50 Appendix E.
REGULATORY GUIDE 1.102, REVISION 1 (SEPTEMBER 1976) - FLOOD PROTECTION FOR NUCLEAR POWER PLANTS FSAR Sections 2.4.2, 2.4.10, 3.4 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.103, REVISION 1 (OCTOBER 1976) - POST-TENSIONED PRESTRESSING SYSTEMS FOR CONCRETE REACTOR VESSELS AND CONTAINMENTS

Position Not applicable to Unit 2.

REGULATORY GUIDE 1.104 (FEBRUARY 1976) - OVERHEAD CRANE HANDLING SYSTEMS FOR NUCLEAR POWER PLANTS

FSAR Section 9.1.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Section 9.1.4.

The Unit 2 crane was compared to RG 1.104, and a report was submitted to the NRC, and preliminary approval was granted by the NRC in a letter dated August 22, 1977.

The polar crane will be tested in accordance with NUREG-0554 and NUREG-0612.

REGULATORY GUIDE 1.105, REVISION 2 (FEBRUARY 1986) - INSTRUMENT SETPOINTS

FSAR Section 7.1.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.106, REVISION 1 (MARCH 1977) - THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR-OPERATED VALVES

FSAR Section 8.3.1

Position The Unit 2 project complies with Regulatory Position (Paragraph C) of this guide. Unit 2 utilizes Position 1, Method (b).

The thermal overload on all safety-related MOVs is bypassed by any automatic safety signal or manually by the operator holding the spring return control switch. Annunciation is provided in the control room for those overload control conditions. An example is shown on Drawing Nos. ESK-6CSL02 and ESK-6CSL03 in the drawing package.

REGULATORY GUIDE 1.107, REVISION 1 (FEBRUARY 1977) - QUALIFICATIONS FOR CEMENT GROUTING FOR PRESTRESSING TENDONS IN CONTAINMENT STRUCTURES

Position Not applicable to Unit 2.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.108, REVISION 1 (AUGUST 1977) - PERIODIC TESTING OF DIESEL GENERATOR UNITS USED AS ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS FSAR Sections 8.3.1.1.2, 14.2 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide except as indicated below. The IEEE-387-1977 (Section 3.7) definitions of Continuous Rating and Short-Time Rating are applied to the diesel generator continuous rating and 2-hr rating referred to in Section C.2.a.3 of the regulatory guide. Section 3.8 of the Technical Specifications details the periodic testing requirements of the diesel generator units. See the Technical Specifications for periodic testing requirements of diesel generator units in lieu of Section C.2.d of the regulatory guide. The Unit 2 Technical Specifications incorporate appropriate surveillance testing requirements that are necessary to minimize mechanical stress and wear on diesel engines. The reporting requirements of Section C.3.b will not be followed. Diesel reliability will be documented in accordance with Regulatory Guide 1.160 (Maintenance Rule).
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 10 CFR PART 50, APPENDIX I FSAR Sections 11.2, 11.3 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 1.110, REVISION 0 (MARCH 1976) (FOR COMMENT) - COST-BENEFIT ANALYSIS FOR RADWASTE SYSTEMS FOR LIGHT-WATER-COOLED NUCLEAR POWER REACTORS FSAR Section Chapter 11 Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
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 FSAR Sections 2.3.5, 11.3, 11A Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Sections 11.3 and 11A.

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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.112, REVISION 0-R (MAY 1977) - CALCULATION OF RELEASES OF RADIOACTIVE MATERIALS IN GASEOUS AND LIQUID EFFLUENTS FROM LIGHT-WATER-COOLED POWER REACTORS

FSAR Sections 2.3.4, 11.2.3, 11.3.3, 15.7.1, 15.7.2, 15.7.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

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

FSAR Sections 2.4.12, 2.4.13, 11.2, 15.7.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.114, REVISION 1 (NOVEMBER 1976) - GUIDANCE ON BEING OPERATOR AT THE CONTROLS OF A NUCLEAR POWER PLANT

FSAR Section 13.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.115, REVISION 1 (JULY 1977) - PROTECTION AGAINST LOW-TRAJECTORY TURBINE MISSILES

FSAR Section 3.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below and in Section 3.5.1.3.

Paragraph C4: The protection of essential systems located within the low-trajectory missile strike zone is acceptable if the probability of damage summed over all structural cubicles containing such systems is less than 10^{-7} per annum.

REGULATORY GUIDE 1.116, REVISION 0-R (MAY 1977) - QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF MECHANICAL EQUIPMENT AND SYSTEMS

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

REGULATORY GUIDE 1.117, REVISION 1 (APRIL 1978) - TORNADO DESIGN CLASSIFICATION

FSAR Sections 3.3, 3.5.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.118, REVISION 2 (JUNE 1978) - PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS

FSAR Sections 7.1.2, 8.1, 8.3.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

Regulatory Position C.6

Circuit response time tests will normally be conducted by connecting jumper wires to terminals in the termination cabinets permanently wired to spare contacts inside PGCC panels. However, where spare contacts and terminals are not available for response time tests, the jumper wires will be attached to appropriate dedicated terminals.

REGULATORY GUIDE 1.119 (JUNE 1976) - SURVEILLANCE PROGRAM FOR NEW FUEL ASSEMBLY DESIGNS

Position This regulatory guide was withdrawn by the NRC on June 3, 1977.

REGULATORY GUIDE 1.120, REVISION 1 (NOVEMBER 1977) (FOR COMMENT) - FIRE PROTECTION GUIDELINES FOR NUCLEAR POWER PLANTS

FSAR Sections 9.5.1, Appendix 9A, Chapter 13

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The Unit 2 design is in accordance with Branch Technical Position CMEB 9.5-1, Revision 2, July 1981, as described in FSAR Section 9.5.1 and Appendix 9A.

REGULATORY GUIDE 1.121 (AUGUST 1976) (FOR COMMENT) - BASES FOR PLUGGING DEGRADED PWR STEAM GENERATOR TUBES

Position RG 1.121 applies to PWR plants and therefore is not applicable to the Unit 2 project.

REGULATORY GUIDE 1.122, REVISION 1 (FEBRUARY 1978) - DEVELOPMENT OF FLOOR DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF FLOOR-SUPPORTED EQUIPMENT OR COMPONENTS

FSAR Section 3.7A.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.123, REVISION 1 (JULY 1977) - QUALITY ASSURANCE REQUIREMENTS FOR CONTROL OF PROCUREMENT OF ITEMS AND SERVICES FOR NUCLEAR POWER PLANTS

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described as follows:

Certain standard catalog or nonengineered items may be processed without seller prequalification. This alternative method is described in Section 7, paragraphs 1.4.1, 1.4.2, 1.4.3, and 3.1.2 of the Quality Assurance Program for Unit 2.

* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

REGULATORY GUIDE 1.124, REVISION 1 (JANUARY 1978) - SERVICE LIMITS AND LOADING COMBINATIONS FOR CLASS 1 LINEAR-TYPE COMPONENT SUPPORTS

FSAR Sections 3.9A.3, 3.9B.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described as follows:

BOP

1. Regulatory Position C.4 The increase of the design limits for bolts in shear as specified in NF-3231.1(a) and (c) should be limited to 0.70 of the bolting material shear ultimate at temperature.

2. Regulatory Position C.8 Supports for the active components that are required only during an emergency or faulted plant condition, and that are subjected to loading combinations described in Regulatory Positions C.6 and C.7, should be designed within the design limits described in Regulatory Position C.5 or other justifiable design limits.

3. Regulatory Position C.5a Paragraph C.5.a should be revised as follows:

   The stress limits of XVII-2000 of Section III and Regulatory Position 3 of this guide should not be exceeded for component supports designed by the linear elastic analysis method. These stress limits may be increased according to the provisions of NF-3231.1(a) of Section III and Regulatory Position 4 of this guide, when effects resulting from constraint of free-end displacement and anchor motion are added to the loading combination.

The following is an addition to the regulatory guide as implemented on the Unit 2 project:

The bending stress limit F resulting from tension and bending in structural members, as specified in Appendix XVII-2214 of ASME Section III, Division 1, should be the smaller value of 0.66 S_y or 0.55 S_u for compact sections, 0.75 S_y or 0.63 S_u for doubly symmetrical members with bending about the minor axis, and 0.6 S_y or 0.5 S_u for box-type flexural members and miscellaneous members.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.124, REVISION 1 (JANUARY 1978) (cont'd.)

NSSS

RG 1.124 Revision 1 (January 1978) was issued after the docketing date for Unit 2. However, Unit 2 complies with the indicated item of the Regulatory Position, described as follows. The remaining design analysis criteria of the regulatory guide are adequately addressed by conservatisms in the existing ASME III Code.

1. Paragraph C.2 Ultimate strength temperature correlation of this guide was used in regions adjacent to pipe having high temperatures. Additionally, the critical buckling strength limits of ASME III Appendix XVII, Paragraph 2110(b), are observed.

REGULATORY GUIDE 1.125, REVISION 1 (OCTOBER 1978) - PHYSICAL MODELS FOR DESIGN AND OPERATION OF HYDRAULIC STRUCTURES AND SYSTEMS FOR NUCLEAR POWER PLANTS

FSAR Section 2.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.126, REVISION 1 (MARCH 1978) - AN ACCEPTABLE MODEL AND RELATED STATISTICAL METHODS FOR THE ANALYSIS OF FUEL DENSIFICATION

FSAR Section Chapter 5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision), and General Electric Standard Application for Reactor Fuel - United States Supplement, NEDE-24011-P-A-US (latest approved revision), are used to comply with the requirement of this regulatory guide.

REGULATORY GUIDE 1.127, REVISION 1 (MARCH 1978) - INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

Position Not applicable to Unit 2.

REGULATORY GUIDE 1.128, REVISION 1 (OCTOBER 1978) - INSTALLATION DESIGN AND INSTALLATION OF LARGE LEAD STORAGE BATTERIES FOR NUCLEAR POWER PLANTS

FSAR Sections 8.1, 8.3.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide with the following exception: The requirements and recommendations contained in IEEE-484-1987 may be applied to replacement of safety-related batteries in lieu of those contained in IEEE-484-1975.

REGULATORY GUIDE 1.129, REVISION 1 (FEBRUARY 1978) - MAINTENANCE, TESTING, AND REPLACEMENT OF LARGE LEAD STORAGE BATTERIES FOR NUCLEAR POWER PLANTS

FSAR Sections 8.1, 8.3.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, with the exception of intervals between the battery service tests which are per the Technical Specifications.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

<u>REGULATORY GUIDE 1.130, REVISION 1 (OCTOBER 1978)</u> - DESIGN LIMITS AND LOADING COMBINATIONS FOR CLASS 1 PLATE-AND-SHELL TYPE COMPONENT SUPPORTS

<u>FSAR Section</u> 3.9B.3

RG 1.130 Revision 0 (July 1977) was issued after the docketing date for Unit 2 and work was in progress. However, Unit 2 complies with the indicated items of the Regulatory Position of this guide through the alternative approach, described as follows. The remaining design analysis criteria of this regulatory guide are adequately addressed by conservatisms in the existing ASME III Code.

1. <u>Paragraph C.2</u> Ultimate strength temperature correlation of this guide was used in regions adjacent to pipe having high temperatures.
2. <u>Paragraph C.3</u> Regulatory Position C.4, with alternate conservative collapse criteria developed by the NSSS supplier for plates and shells, was used in lieu of Regulatory Position C.3.

<u>REGULATORY GUIDE 1.131, REVISION 0 (AUGUST 1977) (FOR COMMENT)</u> - QUALIFICATION TESTS OF ELECTRICAL CABLES, FIELD SPLICES, AND CONNECTIONS FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

<u>FSAR Section</u> 3.11

<u>Position</u> The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

<u>BOP</u>

Complies with this regulatory guide.

<u>NSSS</u>

This regulatory guide is not applicable for the GE scope of supply because GE-supplied cabling does not experience severe environmental conditions (control room environment) and is qualified as part of the PGCC floor section module.

<u>REGULATORY GUIDE 1.132, REVISION 1 (MARCH 1979)</u>

<u>FSAR Sections</u> 2.5, 3.7A.2

<u>Position</u> The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

This guide was originally issued in September 1977, 6 yr after the field work for the foundation investigation was performed in late 1971. The results were provided in a report* dated May 4, 1972. Although the investigation predates the guide, the work performed was well documented and adequate to support the Construction Permit Application and complies with the intent of the guide.

For any aspect of the Unit 2 site, investigation performed after March 30, 1979, conforms to this regulatory guide.

* Report: Foundation Investigation, Nine Mile Point Nuclear Station, Proposed Unit 2, Scriba, New York, Niagara Mohawk Power Corporation.

TABLE 1.8-1
(Sheet 42 of 49)

CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.133, REVISION 1 (MAY 1981) - LOOSE-PART DETECTION PROGRAM FOR THE PRIMARY SYSTEM OF LIGHT-WATER REACTORS

FSAR Section 4.4.6.1

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

1. Paragraph C.1.g The audio/visual alarm capability is not qualified to remain functional following seismic events. As an alternative, plant operating procedures will require the operator to verify the operability of the LPMS following any detected seismic event. If inoperable, the operator will initiate any appropriate maintenance activities to restore the system to operability. The LPMS need not be qualified according to the requirements of RG 1.89.

2. Paragraph C.3.a.3 and C.5.c The channel calibration is no longer performed on a periodic basis.

3. Paragraph C.5 The loose-part detection system does not meet the criteria of 10CFR50.36 for retention in the Technical Specifications.

REGULATORY GUIDE 1.134, REVISION 2 (APRIL 1987) - MEDICAL EVALUATION OF LICENSED PERSONNEL FOR NUCLEAR POWER PLANTS

FSAR Section None

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The medical requirements for personnel requiring operator licenses, as detailed in ANSI/ANS-3.4-1983 and endorsed by this guide, will be implemented.

REGULATORY GUIDE 1.135 (SEPTEMBER 1977) (FOR COMMENT) - NORMAL WATER LEVEL AND DISCHARGE AT NUCLEAR POWER PLANTS

FSAR Sections 2.4, 9.2.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.136, REVISION 2 (JUNE 1981) - MATERIALS FOR CONCRETE CONTAINMENTS

FSAR Sections 3.8.1, 3.8.2, 3.8.3, 3.8.4, 3.8.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

RG 1.136 and ACI 359 (or ASME III - Division 2) were formally issued in 1977 and 1975, respectively, and subsequently reissued thereafter. The construction permit for this project following NRC evaluation of the Unit 2 PSAR was received in June 1974. The reissue of RG 1.136, as Revision 2 in June 1981, incorporates the recommendations of several regulatory guides under this regulatory guide with the intention of withdrawing RG 1.10, 1.15, 1.18, 1.19, 1.55, and 1.103. Due to the advanced stage of procurement, fabrication, and construction, it was not feasible to adopt the changes contained in Revision 2 of this guide. The NRC Safety Evaluation Report (SER) was issued for this project, indicating acceptance to using ACI 318 for the design of concrete containment.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.136, REVISION 2 (JUNE 1981) (cont'd.)

The design of the Unit 2 primary containment is in accordance with RG 1.10, 1.15, 1.18, 1.19, 1.55, and 1.103 (as previously described in lieu of RG 1.136).

REGULATORY GUIDE 1.137, REVISION 1 (OCTOBER 1979) - FUEL-OIL SYSTEMS FOR STANDBY DIESEL GENERATORS

FSAR Section 9.5.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide except for the alternate approach described in the Unit 2 Technical Specifications and Technical Specification Bases.

REGULATORY GUIDE 1.138, REVISION 0 (APRIL 1978) (FOR COMMENT) - LABORATORY INVESTIGATIONS OF SOILS FOR ENGINEERING ANALYSIS AND DESIGN OF NUCLEAR POWER PLANTS

FSAR Sections 2.5, 3.7A.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The results of laboratory work performed for the foundation investigation were submitted in a report* dated 6 yr prior to the issuance of the guide. The work performed was well documented and adequate to support the Construction Permit Application and complies with the intent of the guide.

Laboratory investigations performed after December 1, 1978, were in conformance with this regulatory guide.

* Report: Foundation Investigation, Nine Mile Point Nuclear Station, Proposed Unit 2, Scriba, New York, Niagara Mohawk Power Corporation.

REGULATORY GUIDE 1.139, REVISION 0 (MAY 1978) (FOR COMMENT) - GUIDANCE FOR RESIDUAL HEAT REMOVAL

FSAR Sections 5.4.7, 6.3

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

Paragraph C.1.b states: "In demonstrating that the system can perform its function assuming a single failure, limited operator action outside the control room would be acceptable if suitably justified." The common RHR shutdown cooling suction line valves are in two divisions (Division I - the outside valve; Division II - the inside valve) to satisfy containment isolation criteria. In the event that the RHR shutdown suction line is not available during shutdown because of a single-valve failure (loss of a division of emergency power), either valve can be opened manually with limited operator action or by establishing an alternate shutdown cooling path.

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

FSAR Section 9.4.3

Position Regulatory Guide 1.140 applies only to the radwaste building general area and equipment exhaust systems, each of which is designed to remove only particulate matter. Because charcoal adsorbers are not provided, the sections of the guide relating to adsorbers and iodine adsorption are not addressed. The air filtration units are nonsafety related; however, redundancy is provided for reliability and ease of maintenance.

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below:

1. Paragraph c.2.b - Equipment exhaust system operating capacity is 47,800 cfm. HEPA filter banks are arranged five cells high and seven cells wide, for a total of 35 cells. Maximum air flow through each cell is 1,366 cfm. The filter bank configuration was dictated by spatial limitations. Each filter cell is rated by the manufacturer for an air flow of 1,430 cfm.

2. Paragraph c.2.f - Each HEPA filter casing and the enclosure in which it is mounted is leak tested in accordance with the guide. All ductwork under positive pressure is tested in accordance with procedures of the Associated Air Balance Council (AABC). Ductwork under negative pressure (suction side of fans) will not be leak tested because any leakage would be into the ductwork and would therefore be processed through filters.

3. Paragraph c.3.i - Displacement criteria based on normal industry practice will be used to determine vibration levels. The maximum vibration velocity method of ANSI N509-1980 imposes unrealistic requirements for certain operating speeds.

4. Paragraph c.3.l - Exception is taken to Section 5.9 of ANSI N509-1980 as follows:

   a. Dampers are designed, fabricated, and installed to preclude the uncontrolled release of radioactivity, thereby satisfying the intent of Section 5.9.7. Leakage rates shall be derived from tests conducted in accordance with AMCA 500 and may be the result of project-specific tests or other tests conducted with dampers of the same design. The damper manufacturer is responsible for ensuring that all test reports are maintained on file and are readily available for verification.

   b. Shaft diameters are the damper manufacturer's standard sizes. The shaft diameter is 1/2 in on dampers less than 24 in in length and 3/4 in on dampers 24 in to 48 in in length.

REGULATORY GUIDE 1.141, REVISION 0 (APRIL 1978) (FOR COMMENT) - CONTAINMENT ISOLATION PROVISIONS FOR FLUID SYSTEMS

FSAR Section 6.2.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described in Section 6.2.4.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.142, REVISION 1 (OCTOBER 1981) - SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)

FSAR Section 3.8.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The RG 1.142 and ACI 349-76 (discussed in this regulatory guide) were originally issued in 1978 and 1976, respectively. RG 1.142 was subsequently revised and reissued in 1981. The construction permit for this project, following NRC evaluation of the Unit 2 PSAR, was received in June 1974. A supplement to ACI 349-76 was issued in 1979. Due to the advanced stage of design, procurement, fabrication, and construction, it is not feasible to assure compliance to this guide. The design of safety-related structures (other than concrete primary containment) meets or exceeds the requirements of ACI 318-71 or ACI 318-77, as explained in FSAR Section 3.8.4.2, which were accepted to provide an adequate basis for design of Category I structures. The NRC SER was issued for this project, indicating acceptance of ACI 318-71 for the design of concrete primary containment.

The design of the Unit 2 primary containment is in accordance with RG 1.10, 1.15, 1.18, 1.19, 1.55, and 1.103 (as previously described in lieu of RG 1.142).

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

FSAR Sections 15.7.1, 11.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

A. Liquid Waste System

The fiberglass tanks purchased for the LWS have been designed in accordance with the National Institute of Standards and Technology (NIST) Product Standard (PS) PS 15-69, Custom Contact-Molded Reinforced-Polyester Chemical-Resistant Process Equipment, as identified in NMP2 PSAR, Table C-10b.

NBS PS 15-69 provides the necessary design and fabrication requirements to ensure the integrity of the tanks without the additional cost of burst testing.

The RWCU phase separator tanks (2LWS-TK6A & 6B), which had been purchased as code-stamped ASME VIII vessels, had their code stamps removed because they were not rehydrotested after a nozzle was added to the top head of each of the two vessels in the field. The vessels still satisfy the intent of the requirements of this regulatory guide in that they are designed and fabricated to the requirements of ASME VIII (including the added nozzles) using materials which meet ASME VIII requirements, and the shop hydrotest established the integrity of the vessels before the nozzles were added. The nozzles were added near the top of the vessels' heads and the vessels see only atmospheric operating conditions (although designed for a nominal 15-psi design pressure). The new nozzles were added to allow improved operation of the vessels' level transmitters and are identical to the original level transmitter nozzles which were blind flanged and abandoned. Therefore, the added nozzles do not affect the proven integrity of the vessels in this application.

REGULATORY GUIDE 1.143, REVISION 1 (OCTOBER 1979) (cont'd.)

The Thermex unit (2LWS-FLT102), which is leased equipment, uses CPVC and PVC components. The Thermex unit is connected to plant components using reinforced, noncollapsible hoses. The equipment vendor has evaluated these components as being suitable for processing low-level radioactive waste. All thermoplastic materials (CPVC and PVC components) comply with ASTM material and dimensional standards. Assembled liquid piping or hoses are hydrostatically tested at 150 percent of the maximum design operating pressure for the limiting assembly. Chemical transfer hoses (nonmetallic) satisfy the requirements of ANSI B31.1-1992 Appendix III and are inspected/tested/replaced on a routine interval to ensure equipment reliability.

B. Offgas System

The charcoal adsorbers of the offgas system are not designed to the seismic requirements of this regulatory guide.

Offsite dose calculations in accordance with Chapter 15.7.1 of the NMP2 FSAR show that release of gaseous activity due to failure of the charcoal adsorbers results in offsite doses less than 0.5 Rem to the whole body. In accordance with RG 1.29, this permits classification as nonseismic. At the time of design and procurement of the offgas system (July 1974), RG 1.29 Revision 1 established the seismic requirements for the radioactive waste processing systems.

C. Waste Solidification System

The waste solidification system complies with the requirements of NRC Branch Technical Position ETSB11.1 Revision 1 as outlined in Werner and Pfleiderer Corporation (WPC) Topical Report No. WPC-VRS-001 Revision 1, dated May 1978, with exceptions as discussed in Section 11.4.3. The waste sludge tank is designed, fabricated, examined, and tested (hydrotest at 1.5 times design) in accordance with the requirements of ASME Code Section VIII, Division 1, with no codes stamp. The WPC topical report lists API 620 or 650 for this tank.

The WPC Topical Report has been accepted by the NRC as satisfying the requirements of ETSB11.1 Revision 1, which are consistent with the requirements of RG 1.143. For the waste sludge tank, the requirements of ASME VIII are more stringent than the requirements of API 620 or 650.

REGULATORY GUIDE 1.144, REVISION 1 (SEPTEMBER 1980) - AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS

FSAR Section Chapter 17

Position* The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The preaudit and postaudit conferences required by Sections 4.3.1 and 4.3.3 of ANSI N45.2.12-1977 may be fulfilled by a variety of communications such as telephone conversations.

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* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.145, REVISION 0 (AUGUST 1979) (FOR COMMENT) - ATMOSPHERIC DISPERSION MODELS FOR POTENTIAL ACCIDENT CONSEQUENCE ASSESSMENTS AT NUCLEAR POWER PLANTS

FSAR Sections 2.3, 13.3, 15.7

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 1.146, REVISION 0 (AUGUST 1980) - QUALIFICATION OF QUALITY ASSURANCE PROGRAM AUDIT PERSONNEL FOR NUCLEAR POWER PLANTS

FSAR Section Chapter 17

Position* The Unit 2 project complies with Regulatory Position (Paragraph C) of this guide.

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* This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR supersedes this commitment.

REGULATORY GUIDE 1.147, LATEST APPROVED REVISION - IN-SERVICE INSPECTION CODE CASE ACCEPTABILITY - ASME SECTION XI DIVISION I

FSAR Section 14

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

In accordance with 10CFR50.55a(g)(2), the NMP2 First Ten-Year Interval Inservice Inspection Program was based on the 1983 Edition of ASME Section XI, Summer 1983 Addenda. Code cases included in these programs are identified in the Inservice Inspection Program Plan (First Ten Year). Subsequent Ten-Year Interval ISI, ISPT, and IST programs will be based on the requirements and Code Edition set forth in 10CFR50.55a.

REGULATORY GUIDE 1.148 (MARCH 1981) - FUNCTIONAL SPECIFICATION FOR ACTIVE VALVE ASSEMBLIES IN SYSTEMS IMPORTANT TO SAFETY IN NUCLEAR POWER PLANTS

FSAR Section 5.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

BOP

Other safety-related valve assemblies classified as Quality Group A, B, or C in RG 1.26 comply with the regulatory guides as described below.

a. Section C.2.a, Valve Application Characteristics

The frequency of use for each safety-related valve assembly is not specified. The normal (open/closed) position is not specified, except in the case of safety-related butterfly and solenoid valve assemblies.

b. Section C.2.b, Structural Requirements

The dynamic loading and the piping frequency response spectra are not specified. Potential water hammer is not considered when establishing the maximum differential pressure across a valve.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.148 (MARCH 1981) cont'd.)

c. Section C.2.c, Operational Requirements

The safety-related function (open/close, remain-as-is) is not specified, except in the cases of ball, butterfly, and solenoid valve assemblies. Motor power requirements for valve assemblies are not specified.

NSSS

Fast-closing isolation valve assemblies classified as Quality Group D in RG 1.26 meet the requirements of ANSI B31.1.0, 1977. They also comply with RG 1.148, dated March 1981, with the following clarification:

a. Section C.2.a, Valve Application Characteristics

The frequency of use for each safety-related valve assembly is not specified. The normal (open/closed) position is not specified, except in the case of safety-related butterfly and solenoid valve assemblies.

b. Section C.2.b, Structural Requirements

The dynamic loading and the piping frequency response spectra are not specified. Potential water hammer is not considered when establishing the maximum differential pressure across a valve.

Main steam isolation valve assemblies comply with RG 1.148, dated March 1981, with the following clarification:

a. Section C.1.c.2, Applicability and Relationship with other Standards

The functional specification does not reference the design specification.

REGULATORY GUIDE 1.149 (APRIL 1981) - NUCLEAR POWER PLANT SIMULATORS FOR USE IN OPERATOR TRAINING

FSAR Section Chapter 13.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide for design and construction.

REGULATORY GUIDE 1.149, REVISION 3 (OCTOBER 2001) - NUCLEAR POWER PLANT SIMULATION FACILITIES FOR USE IN OPERATOR LICENSE EXAMINATIONS

FSAR Section Chapter 13.2

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-1
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CONFORMANCE WITH DIVISION 1 NRC REGULATORY GUIDES

REGULATORY GUIDE 1.155 (AUGUST 1988) - STATION BLACKOUT

FSAR Section 8.3.1.5

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

Unit 2 is evaluated against the requirements of the Station Blackout Rule, 10CFR50.63, using the guidance contained in NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC 87-00 Supplemental Questions/Answers, dated December 27, 1989, and NUMARC 87-00 Major Assumptions, dated December 27, 1989, except where RG 1.155 takes precedence. Table 1 of RG 1.155 provides a cross-reference between the regulatory guide and NUMARC 87-00. Any exceptions to the NUMARC guidance taken by Unit 2 are identified in the SBO documentation (see Letter No. NMP2L 1230, dated April 3, 1990, to NRC, TAC No. 68571).

REGULATORY GUIDE 1.163 (September 1995) – PERFORMANCE-BASED CONTAINMENT LEAK-TEST PROGRAM

FSAR Section 6.2.6

Position The Unit 2 project has taken an alternate approach. Implementation of the performance-based 10CFR50, Appendix J Testing Program is in accordance with NEI 94-01, Revision 2-A, with the following exceptions:

1. The MSIVs measured leakage is excluded from the combined leakage rate of 0.6 La.

2. Primary containment airlocks door seals are tested prior to reestablishing containment integrity when something has been done that would bring into question the validity of the previous airlock door seal test.

This alternative approach was approved by the NRC in License Amendment No. 134, issued by NRC letter dated March 30, 2010.

REGULATORY GUIDE 1.183, REVISION 0 (July 2000) - ALTERNATIVE RADIOLOGICAL SOURCE TERMS FOR EVALUATING DESIGN BASIS ACCIDENTS AT NUCLEAR POWER REACTORS

FSAR Sections 15.4.9, 15.6.4, 15.6.5, 15.7.4

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide as it pertains to the evaluation of the offsite and control room doses for the control rod drop accident, the main steam line break accident, the loss-of-coolant accident and the fuel handling accident.

REGULATORY GUIDE 1.190 (March 2001) – CALCULATIONAL AND DOSIMETRY METHODS FOR DETERMINING PRESSURE VESSEL NEUTRON FLUENCE

FSAR Section 4.1.4.5

Position Evaluations of Unit 2 reactor vessel neutron fluence will use a method that complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-1a

THIS TABLE HAS BEEN DELETED

TABLE 1.8-2
(Sheet 1 of 4)

CONFORMANCE TO DIVISION 8 NRC REGULATORY GUIDE

REGULATORY GUIDE 8.1, REVISION 0 (FEBRUARY 1973) - RADIATION SYMBOL FSAR Section None Position The Unit 2 project complies with Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 8.2, REVISION 0 (FEBRUARY 1973) - GUIDE FOR ADMINISTRATIVE PRACTICES IN RADIATION MONITORING FSAR Section None Position See Section 12.5.3 for an assessment of this Regulatory Guide.
REGULATORY GUIDE 8.3, REVISION 0 (FEBRUARY 1973) - FILM BADGE PERFORMANCE CRITERIA – IF USED FSAR Section None Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 8.4, REVISION 0 (FEBRUARY 1973) - DIRECT-READING AND INDIRECT-READING POCKET DOSIMETERS FSAR Section None Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 8.5, REVISION 1 (MARCH 1981) - CRITICALITY AND OTHER INTERIOR EVACUATION SIGNALS FSAR Section None Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 8.6, REVISION 0 (MAY 1983) - STANDARD TEST PROCEDURES FOR GEIGER-MUELLER COUNTERS FSAR Section None Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.
REGULATORY GUIDE 8.7, REVISION 0 (MAY 1973) - OCCUPATIONAL RADIATION EXPOSURE RECORDS SYSTEMS FSAR Section None Position See Section 12.5.3 and Exhibit 12.1-2 for an assessment of this Regulatory Guide.

TABLE 1.8-2
(Sheet 2 of 4)

CONFORMANCE TO DIVISION 8 NRC REGULATORY GUIDE

<u>REGULATORY GUIDE 8.8, REVISION 3 (JUNE 1978)</u> - INFORMATION RELEVANT TO ENSURING THAT OCCUPATIONAL RADIATION EXPOSURE AT NUCLEAR POWER STATIONS WILL BE AS LOW AS IS REASONABLY ACHIEVABLE

<u>FSAR Sections</u> 11, 12, and 13

<u>Position</u> The Unit 2 project complies with this guide with the following clarifications:

Regarding Position C.2, the recommendations stated in this section of the regulatory guide were considered during the development of the design for Unit 2. The implementation of these recommended ALARA improvements is evidenced in the FSAR and plant drawings.

As part of the ongoing ALARA program, procedure(s) addressing the guidance of Position C.2 will be implemented.

Regulatory Position C.2.g.1 recommends that a radiation monitoring readout be available at the main access control point. The Unit 2 digital radiation monitoring system (DRMS) has a complete console readout in the Radiation Protection office. The purpose of this readout is for Radiation Protection personnel only to monitor radiation levels and respond to unusual occurrences. There is also readout capability in the Technical Support Center (TSC) for monitoring during accident conditions.

The Radiation Protection office is located in the access control building at el 261 ft. Radiation Protection personnel in the office could alert personnel entering the plant if radiologic conditions warranted.

Regulatory Position C.3.a.8.e recommends that the work permit state an estimated exposure time required to complete a task and the estimated dose anticipated from the exposure. A site procedure requires that this information be documented on the Radiation Work Permit (RWP) Request form.

Regulatory Position C.4.a.2 recommends that the counting room facility be equipped with a low background alpha-beta proportional counter. The Unit 2 counting room will utilize a Nuclear Measurements Corporation PC-5 counter or its equivalent. This equipment is a gas flow proportional counter. It provides adequate sensitivity for nuclear power reactor applications. A description of the instrument is in Table 12.5-1. Calibration of the instrument is described in Section 12.5.2.2.1.

Regulatory Position C.4.b.2 recommends that portable high-range (0.1-500 R/hr) ion chambers be provided. Unit 2 will utilize 0-50 R/hr ion chambers (Eberline RO-2A or equivalent). An electronically-quenched Geiger-Mueller detector will be used for radiation fields up to 1,000 R/hr.

Regulatory Position C.4.c.2 recommends the use of a 0-200 mR personnel pocket dosimeter. Unit 2 will utilize 0-200 mR, 0-500 mR pocket dosimeters or equivalent.

Regulatory Position C.4.c.5 recommends hand and foot monitors be used. Unit 2 will use Geiger-Mueller type probes for personnel monitoring; however, these probes will not be in a fixed hand and foot configuration. These Geiger-Mueller type probes may be supplemented by beta and/or gamma sensitive whole body contamination monitors, e.g., friskalls, in accordance with approved Station procedures.

<u>REGULATORY GUIDE 8.9, REVISION 0 (SEPTEMBER 1973)</u> - ACCEPTABLE CONCEPTS, MODELS, EQUATIONS, AND ASSUMPTIONS FOR A BIOASSAY PROGRAM

<u>FSAR Section</u> None

<u>Position</u> See Sections 12.5.3 and Exhibit 12.1-2 for an assessment of this Regulatory Guide.

<u>REGULATORY GUIDE 8.10, REVISION 1-R (MAY 1977)</u> - OPERATING PHILOSOPHY FOR MAINTAINING OCCUPATIONAL RADIATION EXPOSURES AS LOW AS IS REASONABLY ACHIEVABLE

<u>FSAR Sections</u> 12.1, 12.5.3

<u>Position</u> The Unit 2 project complies with this guide.

TABLE 1.8-2
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CONFORMANCE TO DIVISION 8 NRC REGULATORY GUIDE

REGULATORY GUIDE 8.12, REVISION 0 (DECEMBER 1974) - CRITICALITY ACCIDENT ALARM SYSTEM

Position This Regulatory Guide is based on the requirements of 10CFR70.24 and nuclear power plants need not comply with this regulation.

REGULATORY GUIDE 8.13, REVISION 1 (NOVEMBER 1975) - INSTRUCTION CONCERNING PRENATAL RADIATION EXPOSURE

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 8.14, REVISION 1 (AUGUST 1977) - PERSONNEL NEUTRON DOSIMETRY

FSAR Section None

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 8.15, REVISION 0 (OCTOBER 1976) - ACCEPTABLE PROGRAMS FOR RESPIRATORY PROTECTION

FSAR Section None

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below:

Paragraph C.4.h Exception is taken to the recommendation that the medical status of each respirator user is to be reviewed at least annually (NUREG-0041, Section 7.4). In February 1995, 10CFR20 was changed to state that respirator qualifications will include a "physician's determination prior to initial fitting of respirators and...periodically at a frequency determined by a physician that the individual is medically fit to use the respiratory protection equipment."

Paragraph C.8.n Exception is taken to the recommendations of Section 13.2 of NUREG-0041 relative to prohibiting the use of contact lenses with full face-piece respirators.

REGULATORY GUIDE 8.19, REVISION 1 (JUNE 1977) (FOR COMMENT) - OCCUPATIONAL RADIATION DOSE ASSESSMENT IN LIGHT-WATER REACTOR NUCLEAR POWER PLANTS - DESIGN STAGE MAN-REM ESTIMATES

FSAR Section None

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

REGULATORY GUIDE 8.20, REVISION 1 (SEPTEMBER 1979) - APPLICATIONS OF BIOASSAY FOR I-125 AND I-131

FSAR Section

Position The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

TABLE 1.8-2
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CONFORMANCE TO DIVISION 8 NRC REGULATORY GUIDE

REGULATORY GUIDE 8.26, REVISION 0 (SEPTEMBER 1980) - APPLICATIONS OF BIOASSAY FOR FISSION AND ACTIVATION PRODUCTS FSAR Section None Position See Sections 12.5.3 and Exhibit 12.1-2 for an assessment of this Regulatory Guide.
REGULATORY GUIDE 8.27, REVISION 0 (MARCH 1981) - RADIATION PROTECTION TRAINING FOR PERSONNEL AT LIGHT-WATER COOLED NUCLEAR POWER PLANTS FSAR Section None Position See Section 12.5.3 for an assessment of this Regulatory Guide.
REGULATORY GUIDE 8.28, REVISION 0 (AUGUST 1981) - AUDIBLE ALARM DOSIMETERS FSAR Section Position The Unit 2 project complies with this guide with the following clarification: Audible alarm dosimeters may be used in areas of high noise provided that the frequency of observation of accrued dose is increased.
REGULATORY GUIDE 8.29, REVISION 0 (JULY 1981) - INSTRUCTION CONCERNING RISKS FROM OCCUPATIONAL RADIATION EXPOSURE FSAR Section None Position See Section 12.5.3 for an assessment of this Regulatory Guide.

1.9 STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

Table 1.9-1 lists the SRPs, identifies those applicable to Unit 2, and indicates whether or not Unit 2 complies with the acceptance criteria. Where Unit 2 does not comply with the acceptance criteria, a note where there is a justification of the difference is referenced. The notes follow Table 1.9-1.

TABLE 1.9-1
(Sheet 1 of 56)

STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 1: INTRODUCTION AND GENERAL DESCRIPTION OF PLANT				
1.8	Interfaces for Standard Design	1	NA	NA
CHAPTER 2: SITE CHARACTERISTICS				
2.1.1	Site Location and Description	2	X	
2.1.2	Exclusion Area Authority and Control	2	X	
2.1.3	Population Distribution	2	X	
2.2.1-2.2.2	Identification of Potential Hazards in Site Vicinity	2	X	
2.2.3	Evaluation of Potential Accidents	2	X	
2.3.1	Regional Climatology	2	X	
2.3.2	Local Meteorology	2		Note 1
2.3.3	Onsite Meteorological Measurements Programs	2		Note 2
2.3.4	Short-Term Diffusion Estimates for Accidental Atmospheric Releases	1	X	
2.3.5	Long-Term Diffusion Estimates	2	X	
2.4.1	Hydrologic Description	2	X	
	Appendix A	2	X	
2.4.2	Floods	2	X	
2.4.3	Probable Maximum Flood (PMF) on Streams and Rivers	2	NA	NA
2.4.4	Potential Dam Failures	2	NA	NA
2.4.5	Probable Maximum Surge and Seiche Flooding	2	X	
2.4.6	Probable Maximum Tsunami Flooding	2	NA	NA
2.4.7	Ice Effects	2	X	
2.4.8	Cooling Water Canals and Reservoirs	2	NA	NA
2.4.9	Channel Diversions	2	NA	NA
2.4.10	Flood Protection Requirements	2	X	
2.4.11	Cooling Water Supply	2	X	
2.4.12	Groundwater	2		Note 3
	BTP HMB/GSB 1	1	NA	NA
	BTP HGEB 1	2	NA	NA
2.4.13	Accidental Releases of Liquid Effluents in Ground and Surface Waters	2		Note 4
2.4.14	Technical Specifications and Emergency Operation Requirements	2	NA	NA
2.5.1	Basic Geologic and Seismic Information	2	X	
2.5.2	Vibratory Ground Motion	1	X	
2.5.3	Surface Faulting	2	X	
2.5.4	Stability of Subsurface Materials and Foundations	2		Note 5
2.5.5	Stability of Slopes	2		Note 6

TABLE 1.9-1
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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 3: DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS				
3.2.1	Seismic Classification	1		Note 7
3.2.2	System Quality Group Classification	1		Note 8
3.3.1	Wind Loadings	2		Note 9
3.3.2	Tornado Loadings	2	X	
3.4.1	Flood Protection	2	X	
3.4.2	Analysis Procedures	2	X	
3.5.1.1	Internally-Generated Missiles (Outside Containment)	2	X	
3.5.1.2	Internally-Generated Missiles (Inside Containment)	2	X	
3.5.1.3	Turbine Missiles	2		Note 10
3.5.1.4	Missiles Generated by Natural Phenomena	2	X	
	BTP AAB 3-2	1	NA	NA
	BTP ASB 3-2	2	NA	NA
3.5.1.5	Site Proximity Missiles (Except Aircraft)	1	X	
3.5.1.6	Aircraft Hazards	1	X	
3.5.2	Structures, Systems, and Components to be Protected from Externally-Generated Missiles	2	X	
3.5.3	Barrier Design Procedures	1	X	Note 11
3.6.1	Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	1	X	
	BTP ASB 3-1	1		Note 12
3.6.2A	Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping	1		Note 13
	BTP MEB 3-1	1		Note 13
3.6.2B	Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping	1		Note 14
	BTP MEB 3-1	1		Note 14
3.7.1A	Seismic Design Parameters	1	X	
3.7.1B	Seismic Design Parameters	1	X	
3.7.2A	Seismic System Analysis	1		Note 15
3.7.2B	Seismic System Analysis	1	X	
3.7.3A	Seismic Subsystem Analysis	1	X	
3.7.3B	Seismic Subsystem Analysis	1		Note 16
3.7.4	Seismic Instrumentation	1		Note 17
3.8.1	Concrete Containment	1		Note 18
3.8.2	Steel Containment	1	NA	NA
3.8.3	Concrete and Steel Internal Structures of Steel or Concrete Containments	1		Note 19
3.8.4	Other Seismic Category I Structures	1		Note 20
3.8.5	Foundations	1		Note 21
3.9.1A	Special Topics for Mechanical Components	2	X	
3.9.1B	Special Topics for Mechanical Components	2	X	
3.9.2A	Dynamic Testing and Analysis of Systems, Components, and Equipment	2		Note 22
3.9.2B	Dynamic Testing and Analysis of Systems, Components, and Equipment	2		Note 23
3.9.3A	ASME Code Class 1, 2 and 3 Components, Component Supports, and Core Support Structures	1	X	
3.9.3B	ASME Code Class 1, 2 and 3 Components, Component Supports, and Core Support Structures	1		Note 24
3.9.4B	Control Rod Drive Systems	1	X	

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
3.9.5B	Reactor Pressure Vessel Internals	2		Note 25
3.9.6	In-service Testing of Pumps and Valves	2		Note 26
3.10A	Seismic Qualification of Category I Instrumentation and Electrical Equipment	2		Note 27
3.10B	Seismic Qualification of Category I Instrumentation and Electrical Equipment	2	X	
3.11	Environmental Design of Mechanical and Electrical Equipment	2		Note 28
CHAPTER 4: REACTOR				
4.2	Fuel System Design	2		Note 29
4.3	Nuclear Design	2	X	
	BTP CPB 4.3-1	2	NA	NA
4.4	Thermal and Hydraulic Design	1		Note 30
	Appendix	1	NA	NA
4.5.1	Control Rod Drive Structural Materials	2		Note 31
4.5.2	Reactor Internals and Core Support Materials	2		Note 32
4.6	Functional Design of Control Rod Drive System	1	X	
CHAPTER 5: REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS				
5.2.1.1	Compliance with the Codes and Standard Rule 10CFR50.55a	2		Note 33
5.2.1.2	Applicable Codes Cases	2	X	
5.2.2	Overpressurization Protection	1		Note 34
	BTP RSB 5-2	0	NA	NA
5.2.3	Reactor Coolant Pressure Boundary Materials	2		Note 35
	BTP MTEB 5-7	2	NA	NA
5.2.4	Reactor Coolant Pressure Boundary In-service Inspection and Testing	1	X	
5.2.5	Reactor Coolant Pressure Boundary Leakage Detection	1	X	
5.3.1	Reactor Vessel Materials	1		Note 36
5.3.2	Pressure-Temperature Limits	1	X	
	BTP MTEB 5-2	1	X	
5.3.3	Reactor Vessel Integrity	1	X	
5.4	Preface	1	NA	NA
5.4.1.1	Pump Flywheel Integrity (PWR)	1	NA	NA
5.4.2.1	Steam Generator Materials	2	NA	NA
	BTP MTEB 5-3	2	NA	NA
5.4.2.2	Steam Generator Tube In-service Inspection	1	NA	NA
5.4.6	Reactor Core Isolation Cooling System (BWR)	2		Note 37
5.4.7	Residual Heat Removal (RHR) System	2	X	
	BTP RSB 5-1	2	X	
5.4.8	Reactor Water Cleanup System (BWR)	2		Note 38
5.4.11	Pressurizer Relief Tank	2	NA	NA
5.4.12	Reactor Coolant System High-Point Vents	0	X	

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 6: ENGINEERED SAFETY FEATURES				
6.1.1	Engineered Safety Features Materials	2	X	
	BTP MTEB 6-1	2	NA	NA
6.1.2	Protective Coating Systems (Paints) - Organic Materials	2		Note 39
6.2.1	Containment Functional Design	2	NA	NA
6.2.1.1A	PWR Dry Containments, Including Subatmospheric Containments	2	NA	NA
6.2.1.1B	Ice Condenser Containments	2	NA	NA
6.2.1.1C	Pressure Suppression Type BWR Containments	4		Note 40
	Appendix I	1		Note 40
6.2.1.2	Subcompartment Analysis	2		Note 41
6.2.1.3	Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents	1		Note 42
6.2.1.4	Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures	1	NA	NA
6.2.1.5	Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies	2	NA	NA
6.2.2	Containment Heat Removal Systems	3		Note 43
6.2.3	Secondary Containment Functional Design	2	X	
6.2.4	Containment Isolation System	2	X	
6.2.5	Combustible Gas Control in Containment	2		Note 43.1
	Appendix A	2	NA	NA
	BTP CSB 6-2	2	NA	NA
6.2.6	Containment Leakage Testing	2	X	
6.2.7	Fracture Prevention of Containment Pressure Boundary	0		Note 44
6.3	Emergency Core Cooling System	1		Note 45
	BTP RSB 6-1	1	NA	NA
6.4	Control Room Habitability System	2	X	
	Appendix A	2	X	
6.5.1	Engineered Safety Feature Atmosphere Cleanup System	2		Note 46
6.5.2	Containment Spray as a Fission Product Cleanup System	1	NA	NA
6.5.3	Fission Product Control Systems and Structures	2	X	
6.5.4	Ice Condenser as a Fission Product Cleanup System	2	NA	NA
6.6	Inservice Inspection of Class 2 and 3 Components	1	X	
6.7	Main Steam Isolation Valve Leakage Control System (BWR)	2	NA	NA
CHAPTER 7: INSTRUMENTATION AND CONTROLS				
7.1	Instrumentation and Controls - Introduction	2	X	
	Table 7-1 - Acceptance Criteria and Guidelines for Instrumentation and Controls Systems Important to Safety	2	X	
7.2	Reactor Trip System	2	X	
	Appendix A	2	NA	NA
7.3	Engineered Safety Features System	2	X	
	Appendix A	2	NA	NA
7.4	Safe Shutdown Systems	2	X	

TABLE 1.9-1
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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 7: INSTRUMENTATION AND CONTROLS (Cont'd.)				
7.5	Information Systems Important to Safety	2	X	
7.6	Interlock Systems Important to Safety	2	X	
7.7	Control Systems	2	X	
Appendix 7-A	Branch Technical Positions (ICSB)	2		
	BTP ICSB 1 (DOR)	2	NA	NA
	BTP ICSB 3	2		Note 80
	BTP ICSB 4 (PSB)	2	NA	NA
	BTP ICSB 5	2	NA	NA
	BTP ICSB 9	2	NA	NA
	BTP ICSB 12	2	NA	
	BTP ICSB 13	2	NA	NA
	BTP ICSB 14	2	NA	NA
	BTP ICSB 16	2	NA	NA
	BTP ICSB 19	2	NA	NA
	BTP ICSB 20	2	X	
	BTP ICSB 21	2	X	
	BTP ICSB 22	2	X	
	BTP ICSB 25	2	NA	NA
	BTP ICSB 26	2	X	
Appendix 7-B	General Agenda, Station Site Visits	1	NA	NA
CHAPTER 8: ELECTRIC POWER				
8.1	Electric Power - Introduction	2	NA	NA
	Table 8-1 - Acceptance Criteria and Guidelines for Electric Power Systems	2	X	
8.2	Offsite Power System	2	X	
8.3.1	AC Power Systems (Onsite)	2		Note 47
8.3.2	DC Power Systems (Onsite)	2	X	
Appendix 8-A	Branch Technical Positions (PSB)	2		
	BTP ICSB 2 (PSB)	2	NA	NA
	BTP ICSB 4 (PSB)	2	NA	NA
	BTP ICSB 8 (PSB)	2	X	
	BTP ICSB 11 (PSB)	2	X	
	BTP ICSB 15 (PSB)	2	NA	NA
	BTP ICSB 17 (PSB)	2	NA	NA
	BTP ICSB 18 (PSB)	2	X	
	BTP ICSB 21 (PSB)	2	X	
	BTP PSB 1	0	X	
	BTP PSB 2	0	X	
Appendix 8-B	General Agenda, Station Site Visits	0	NA	NA

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 9: AUXILIARY SYSTEMS				
9.1.1	New Fuel Storage	2	X	
9.1.2	Spent Fuel Storage	3	X	
9.1.3	Spent Fuel Pool Cooling and Cleanup System	1		Note 48
9.1.4	Light Load Handling System (Related to Refueling)	2	X	
	BTP ASB 9-1	2	NA	NA
9.1.5	Overhead Heavy Load Handling Systems	0		Note 49
9.2.1	Station Service Water System	2	X	
9.2.2	Reactor Auxiliary Cooling Water Systems	1		Note 50
9.2.3	Demineralized Water Makeup Systems	2		Note 51
9.2.4	Potable and Sanitary Water System	2	X	
9.2.5	Ultimate Heat Sink	2	X	
	BTP ASB 9-2	2	X	
9.2.6	Condensate Storage Facilities	2	NA	NA
9.3.1	Compressed Air System	1	X	
9.3.2	Process and Post-accident Sampling System	2		Note 52
9.3.3	Equipment and Floor Drainage System	2	X	
9.3.4	Chemical and Volume Control System (PWR) (Including Boron Recovery System)	2	NA	NA
9.3.5	Standby Liquid Control System (BWR)	2	X	
9.4.1	Control Room Area Ventilation System	2		Note 53
9.4.2	Spent Fuel Pool Area Ventilation System	2		Note 54
9.4.3	Auxiliary and Radwaste Area Ventilation System	2		Note 55
9.4.4	Turbine Area Ventilation System	2	X	
9.4.5	Engineered Safety Feature Ventilation System	2		Note 56
9.5.1	Fire Protection Program	3		Note 57
	BTP CMEB 9.5.1	2		Note 57
9.5.2	Communications System	2	X	
9.5.3	Lighting Systems	2	X	
9.5.4	Emergency Diesel Engine Fuel Oil Storage and Transfer System	2	X	
9.5.5	Emergency Diesel Engine Cooling Water System	2	X	
9.5.6	Emergency Diesel Engine Starting System	2	X	
9.5.7	Emergency Diesel Engine Lubrication System	2	X	
9.5.8	Emergency Diesel Engine Combustion Air Intake and Exhaust System	2	X	
CHAPTER 10: STEAM AND POWER CONVERSION SYSTEM				
10.2	Turbine Generator	2	X	
10.2.3	Turbine Disk Integrity	1	X	
10.3	Main Steam Supply System	2		Note 58
10.3.6	Steam and Feedwater System Materials	2	X	
10.4.1	Main Condensers	2	X	
10.4.2	Main Condenser Evacuation System	2		Note 59
10.4.3	Turbine Gland Sealing System	2		Note 60
10.4.4	Turbine Bypass System	2	X	

TABLE 1.9-1
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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

SRP Number	Title	Revision	Conformance	Difference
CHAPTER 10: STEAM AND POWER CONVERSION SYSTEM (Cont'd.)				
10.4.5	Circulating Water System	2	X	
10.4.6	Condensate Cleanup System	2	X	
10.4.7	Condensate and Feedwater System	2	X	
	BTP ASB 10-2	2	NA	NA
10.4.8	Steam Generator Blowdown System (PWR)	2	NA	NA
10.4.9	Auxiliary Feedwater System (PWR)	2	NA	NA
	BTP ASB 10-1	2	NA	NA
CHAPTER 11: RADIOACTIVE WASTE MANAGEMENT				
11.1	Source Terms	2	X	
11.2	Liquid Waste Management Systems	2		Note 61
11.3	Gaseous Waste Management Systems	2		Note 62
	BTP ETSB 11-5	0		Note 63
11.4	Solid Waste Management Systems	2	X	
	BTP ETSB 11-3	2	X	
	Appendix 11.4-A	0	NA	NA
11.5	Process and Effluent Radiological Monitoring and Sampling Systems	3	X	Note 79
	Appendix 11.5-A	1	X	
CHAPTER 12: RADIATION PROTECTION				
12.1	Assuring that Occupational Radiation Exposures are as Low as is Reasonably Achievable	2	X	
12.2	Radiation Sources	2		Note 64
12.3-12.4	Radiation Protection Design Features	2		Note 65
12.5	Operational Radiation Protection Program	2		Note 66
CHAPTER 13: CONDUCT OF OPERATIONS				
13.1.1	Management and Technical Support Organization	2	X	
13.1.2-13.1.3	Operating Organization	2	X	
13.2.1	Reactor Operating Training	0	X	Note 78
13.2.2	Training for Non-Licensed Plant Staff	0	X	
13.3	Emergency Planning	2	X	
13.4	Operational Review	2		Note 67
13.5.1	Administration Procedures	0	X	
13.5.2	Operating and Maintenance Procedures	0	X	
13.6	Physical Security	2	X	

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SRP Number	Title	Revision	Conformance	Difference
CHAPTER 14: INITIAL TEST PROGRAM				
14.1	Initial Plant Test Programs - PSAR	2	NA	NA
14.2	Initial Plant Test Programs - FSAR	2		Note 68
14.3	Standard Plant Designs Initial Test Program Final Design Approval (FDA)	1	NA	NA
CHAPTER 15: ACCIDENT ANALYSIS				
15.0	Introduction	2	NA	NA
15.1	Increase in Heat Removal by the Secondary System			
15.1.1-15.1.4	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	1	X	
15.1.5	Steam System Piping Failures Inside and Outside of Containment (PWR)	2	NA	NA
	Appendix A	2	NA	NA
15.2	<u>Decrease in Heat Removal by the Secondary System</u>			
15.2.1-15.2.5	Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)	1	X	
15.2.6	Loss of Non-Emergency AC Power to the Station Auxiliaries	1	X	
15.2.7	Loss of Normal Feedwater Flow	1	X	
15.2.8	Feedwater System Pipe Breaks Inside and Outside Containment (PWR)	1	NA	NA
15.3	Decrease in Reactor Coolant System Flow Rate			
15.3.1-15.3.2	Loss of Forced Reactor Coolant Flow Including Trip of Pump and Flow Controller Malfunctions	1	X	
15.3.3-15.3.4	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	2		Note 69
15.4	Reactivity and Power Distribution Anomalies			
15.4.1	Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition	2	X	
15.4.2	Uncontrolled Control Rod Assembly Withdrawal at Power	2	X	
15.4.3	Control Rod Misoperation (System Malfunction or Operator Error)	2	NA	NA
15.4.4-15.4.5	Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate	1	X	
15.4.6	Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (PWR)	1	NA	NA
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	1		Note 70

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SRP Number	Title	Revision	Conformance	Difference
CHAPTER 15: ACCIDENT ANALYSIS (Cont'd.)				
15.4.8	Spectrum of Rod Ejection Accidents (PWR)	2	NA	NA
	Appendix A	1	NA	NA
15.4.9	Spectrum of Rod Drop Accidents (BWR)	2	X	
	Appendix A	2	X	
15.5	Increase in Reactor Coolant Inventory			
15.5.1-15.5.2	Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	1	X	
15.6	Decrease in Reactor Coolant Inventory			
15.6.1	Inadvertent Opening of a PWR Pressurizer Relief Valve or a BWR Relief Valve	1	X	
15.6.2	Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment	2	X	
15.6.3	Radiological Consequences of Steam Generator Tube Failure (PWR)	2	NA	NA
15.6.4	Radiological Consequences of Main Steam Line Failure Outside Containment (BWR)	2		Note 71
15.6.5	Loss-of-Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary	2		Note 72
15.7	Radioactive Release from a Subsystem or Component			
15.7.1	Waste Gas System Failure	1	NA	NA
15.7.2	Radioactive Liquid Waste System Leak or Failure (Release to Atmosphere)	1	NA	NA
15.7.3	Postulated Radioactive Releases Due to Liquid-Containing Tank Failures	2	X	
15.7.4	Radiological Consequences of Fuel Handling Accidents	1	X	
15.7.5	Spent Fuel Cask Drop Accidents	2	X	
15.8	<u>Anticipated Transients Without Scram</u>			
15.8	Anticipated Transients Without Scram	1		Note 73
CHAPTER 16: TECHNICAL SPECIFICATIONS				
16.0	Technical Specifications	1		Note 74
CHAPTER 17: QUALITY ASSURANCE				
17.1	Quality Assurance During the Design and Construction Phases	2		Note 75
17.2	Quality Assurance During the Operations Phase	2		Note 76
CHAPTER 18: HUMAN FACTORS ENGINEERING				
18.0	Human Factors Engineering/Standard Review Plan Development	0		Note 77

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KEY: NA = Not Applicable

(1) SRP section has been combined with SRP Section 12.3.
(2) SRP section has been combined with SRP Section 13.1.2.

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NOTES

1. STANDARD REVIEW PLAN 2.3.2, REVISION 2, JULY 1981 - LOCAL METEOROLOGY

Difference 1 No topographic description is provided in FSAR Section 2.3.2. Effects of terrain modification and plant structures are also not discussed.

Discussion A description of the topography in the site region is provided in Section 2.5.1. The effects of terrain modification and plant structures on local meteorology are not significant and, therefore, are not expected to have any impact on plant operation. They are discussed in Section 2.3.5.

Difference 2 The wind sensors (Bendix Aerovanes) at the 61-m (200-ft), 30-m (100-ft), and 9-m (30-ft) levels of the onsite meteorological tower did not meet the accuracy and starting speed recommended in RG 1.23 for data collected until July 1982.

Discussion The severe weather conditions encountered on the shoreline of Lake Ontario required the choice of very rugged wind speed equipment prior to the tower's installation in late 1973. The Bendix Aerovane was chosen for its proven ability to withstand the climate of the region as opposed to measuring the infrequent calm hours.

The Bendix Aerovane has a starting speed of about 1.2 m/sec (2.6 mph) and continues to operate with speeds of 0.4 to 0.7 m/sec (1 to 1.5 mph). The wind speed accuracy is ±0.4 m/sec (±1.0 mph) above 4.5 m/sec (10 mph) as opposed to the RG 1.23 criterion of ±0.2 m/sec (±0.5 mph) for all wind speeds. More sensitive wind speed sensors available at that time were prone to icing and physical damage from high wind speeds.

Subsequent to July 1982, new instruments were installed to comply with the regulatory guide.

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2. STANDARD REVIEW PLAN 2.3.3, REVISION 2, JULY 1981 - ONSITE METEOROLOGICAL MEASUREMENTS PROGRAMS

Difference The wind sensors (Bendix Aerovanes) at the 61-m (200-ft), 30-m (100-ft), and 9-m (30-ft) levels of the onsite meteorological tower did not meet the accuracy and starting speed recommended in RG 1.23 for data collected before July 1982.

Discussion See the discussion of Difference 2 for SRP 2.3.2.

3. STANDARD REVIEW PLAN 2.4.12, REVISION 2, JULY 1981 - GROUNDWATER

Difference Section 2.4.12 does not address groundwater.

Discussion The material required by SRP 2.4.12, Groundwater, can be found in FSAR Section 2.4.13. Except for the number change there are no differences noted.

4. STANDARD REVIEW PLAN 2.4.13 - ACCIDENTAL RELEASES OF LIQUID EFFLUENT IN GROUND AND SURFACE WATERS

Difference No chapter/section exists with the required SRP 2.4.13 title.

Discussion Section 2.4.13.3 addresses accidental effects and dilution modeling as required by this SRP acceptance criteria.

5. STANDARD REVIEW PLAN 2.5.4, REVISION 2, JULY 1981 - STABILITY OF SUBSURFACE MATERIALS AND FOUNDATIONS

Difference The acceptance criteria for Section 2.5.4.8, Liquefaction Potential, states that liquefaction potential assessments using both deterministic and probabilistic approaches are desirable. However, only the deterministic method was used.

Discussion All major Category I structures for Unit 2 are founded on sound bedrock.

The deterministic approach discussed in Section 2.5.4.8 for the analysis of liquefaction potential under a few minor structures founded in soil backfill is considered adequate and does not require a supplementary probabilistic analysis.

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6. STANDARD REVIEW PLAN 2.5.5, REVISION 2, JULY 1981 - STABILITY OF SLOPES

Difference Only the deterministic method was used in the design and analysis of slopes.

Discussion The revised SRP promotes both deterministic and probabilistic approaches to slope design analysis, indicating that the latter method is desirable rather than mandatory, and that it may be employed by the NRC staff itself. To analyze and design the manmade slopes, which are discussed in FSAR Section 2.5.2.2, only the deterministic approach was utilized. It is considered adequate and does not require a supplementary probabilistic analysis.

7. STANDARD REVIEW PLAN 3.2.1, REVISION 1 - SEISMIC CLASSIFICATION

All differences between seismic classifications in RG 1.29, Revision 3, and the Unit 2 design are indicated in FSAR Table 3.2-1. A discussion of the differences is also included in the table.

8. STANDARD REVIEW PLAN 3.2.2, REVISION 1 - SYSTEM QUALITY GROUP CLASSIFICATION

All differences between System Quality Group Classification in RG 1.26, Revision 3, and the Unit 2 design are indicated in FSAR Table 3.2-1. A discussion of the differences is also included in the table.

9. STANDARD REVIEW PLAN 3.3.1, REVISION 2 - WIND LOADINGS

Difference The acceptance criteria for Revision 1 of SRP 3.3.1 (NUREG-75/087) are allowed using either ASCE Paper No. 3269 or ANSI A58.1-1972 as the basis for wind design. The acceptance criteria for Revision 2 of SRP 3.3.1 (NUREG-0800) considers ANSI A58.1 as the base document while permitting use of ASCE Paper No. 3269 only for cases which ANSI A58.1 does not cover.

Unit 2 is designed using ASCE Paper No. 3269 consistent with the PSAR commitment and with the state of the art available at the time of plant design.

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Discussion A review of ANSI A58.1, for derivation of wind pressure for a typical structure, or parts and portions of a structure, indicates that the values thus derived are essentially identical to those derived using ASCE Paper No. 3269.

10. STANDARD REVIEW PLAN 3.5.1.3, REVISION 2 - TURBINE MISSILES

Difference For Unit 2 the following was used in lieu of paragraph II.1:

> The protection of essential systems located within the low-trajectory missile strike zone is acceptable if the probability of damage summed over all structural cubicles containing such systems is less than 10^{-7} per annum.

Discussion The purpose for using an annual damage probability of 10^{-7} and an annual turbine failure rate of 10^{-4}, rather than directly using the resulting factor of 10^{-3}, is to permit compliance with Section III.2 of SRP 3.5.1.3, Revision 2. This allows the turbine failure rate of 10^{-4} per annum to be subdivided as follows:

> $P = 6 \times 10^{-5}$ per turbine year for design speed failures
>
> $P = 4 \times 10^{-5}$ per turbine year for destructive overspeed failures

The reason for evaluating acceptability by summing probabilities over cubicles containing essential systems, rather than by summing over the essential systems themselves, is to simplify the analysis. It is impractical to evaluate the strike probability for each system, considering the complex routing and the possibility for minor layout changes during plant design. By performing the evaluation on the basis of cubicles containing essential systems, this difficulty is avoided while still ensuring that all essential systems are considered in the evaluation.

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11. STANDARD REVIEW PLAN 3.5.3, REVISION 1 - BARRIER DESIGN PROCEDURES

Difference The tornado missile spectrum in Table 2 of this SRP is not used.

Discussion Unit 2 is designed to withstand the tornado-generated missiles of Spectrum A of SRP 3.5.1.4, Revision 2.

See Section 3.5.3 for further discussion.

12. CONFORMANCE TO BTP ASB 3-1, REVISION 1, ATTACHED TO STANDARD REVIEW PLAN 3.6.1 - PROTECTION AGAINST POSTULATED PIPING FAILURES IN FLUID SYSTEMS OUTSIDE CONTAINMENT

Difference 1 Section B.1.a.1 states that "even though portions of the main steam and feedwater lines meet the break exclusion requirements of B.1.6 of BTP MEB 3-1, they should be separated from essential equipment. In order for essential equipment to be properly separated, the essential equipment must be protected from the jet impingement and the environmental effects of an assumed longitudinal break of the main steam line and feedwater lines. Each assumed longitudinal break should have a cross-sectional area of at least one square foot and should be postulated to occur at a location that has the greatest effect on essential equipment."

FSAR Section 3.6A.2.1.5 states that "regardless of the fact that all conditions [for break exclusion piping] have been met, a crack is postulated in the main steam or feedwater piping in the main steam tunnel. The crack in the pipe, equal in area to a single-ended pipe rupture, is considered a singular event. Pipe whip and jet impingement are not considered, and a single active failure is not taken as a concurrent event."

Discussion As a result of the issuance of SRPs 3.6.1 and 3.6.2 in 1975, the Unit 2 pipe rupture criteria were revised in a letter to the NRC on July 31, 1978, (Section 3.6, Reference 1) to show compliance to the latest requirements. Subsequently, it was recognized that there were additional concerns in the main steam tunnel. The Unit 2 plant was modified to incorporate the requirements outlined in a letter to the ASLAB from the NRC, dated October 4, 1978, concerning Carolina Power and Light's Shearon Harris plant. The NRC position was as follows:

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STEAM TUNNEL DESIGN FOR NUCLEAR PLANTS

We have revised our requirements for the design of nuclear power plants relating to postulated high energy line breaks outside the containment. Specifically the revision will require that the compartment between the containment and the turbine building, which houses the main steam lines and feedwater lines and the isolation valves for these lines, be designed to consider the pressure and environmental effects from an assumed break, equivalent to the flow area of a single-ended pipe rupture in these lines. This revision will require that if this assumed break could cause the collapse of this compartment, then the collapse should not jeopardize the safe shutdown of the plant.

Furthermore, it will require that essential equipment located within the compartment, or adjacent to the compartment, be designed to withstand the environmental effects resulting from the above break.

The results of a postulated pipe break in a high energy line (one in which either the pressure exceeds 275 psig or the temperature exceeds 200°F) are pipe whip, jet impingement, and the environmental effects of pressure, temperature, humidity and flooding. With the exception of certain break exclusion regions, pipe breaks are postulated at terminal ends and other points of relatively high stress and fatigue. Within the break exclusion region, which is limited to the containment penetration area, a combination of low stress and fatigue design coupled with augmented in-service inspection is used to assure that no pipe breaks will occur due to the design loads. However, the stress is not normally low enough to reasonably preclude the possibility of a postulated pipe crack in the region. As such, it is prudent to require that the surrounding pipe tunnel be designed to withstand the effects of a postulated pipe crack. These effects are of an extreme environmental nature for equipment in the vicinity and include pressure, temperature, humidity and flooding. Because of the augmented in-service inspection and the low stress and fatigue design, it is reasonable to assume that a postulated pipe crack will be detected and repaired before it becomes

through wall or, at the latest, in its initial phase of leakage. The flow area for postulated pipe cracks is conservatively selected as the cross-sectional area of the pipe, however, to ensure that the largest possible crack is enveloped by the design.

Implementation of this position will ensure that essential equipment will not be arbitrarily housed in the main steam tunnel such that safety by separation is maintained.

Difference 2 Section B.1.c states that "a program should be developed to ensure that the system stresses due to long-term changes in the system and its supports and restraints, such as due to pipe relaxation and differential settling, will not be adversely affected by the restraints. Details of the methods used to obtain these assurances should be submitted to the staff for review."

Discussion Clearances at pipe whip restraints were extensively reviewed by recording piping displacements at selected whip restraints during startup testing. A comparison between predicted and measured pipe movements was made. It was concluded that piping systems would not experience any additional stress due to these long-term changes provided that:

1. the existing clearances are maintained, or

2. if the maximum pipe movements as predicted by reanalysis are changed, the new displacements at the restraint location are reviewed on a case-by-case basis to ensure that the intent of BTP MEB 3-1 is met.

Difference 3 Section B.2.d states that "piping classification as required by Regulatory Guide 1.26 should be maintained without change until beyond the outboard restraint. If the restraint is located at the isolation valve, a classification change at the valve interface is acceptable." For Unit 2, the piping classification change is made at the valve (not beyond the outboard restraint) in accordance with RG 1.26.

Discussion Although the classification change is made at the valve, the piping between the valve and the first restraint outside containment is B31.1 (for main steam and

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feedwater) and ASME Section III, Class 2 and 3 (for RCIC and RWCU, respectively). Additionally, the piping meets the stringent break exclusion requirements in Item B.1.b of BTP MEB 3-1. It is therefore concluded that this will not degrade the safety of the plant.

13. STANDARD REVIEW PLAN 3.6.2A, REVISION 1, JULY 1981, BRANCH TECHNICAL POSITION MEB 3-1 - DETERMINATION OF RUPTURE LOCATIONS AND DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

Difference 1 Section B.1.e states that "with the exceptions of those portions of piping identified in B.1.b, leakage cracks should be postulated in ASME Code Section III, Class 1, piping where the stress range by Eq. (10) of Paragraph NB-3653 exceeds 1.20 and in Class 2 or 3 or nonsafety class piping where the stress by the sum of Eq. (9) and (10) of Paragraph NC/ND 3652 exceeds 0.4. Nonsafety piping which has not been evaluated to obtain similar stress information shall have cracks postulated at locations that result in the most severe environmental consequence." For high-energy piping in areas other than the containment penetration, Unit 2 postulates breaks in accordance with Sections B.1.a and B.1.c.

Discussion By evaluating the effects of jet impingement, pipe whip, environment, etc., for high-energy piping systems in accordance with Sections B.1.a and B.1.c, any event that could adversely affect the safety of the plant will be considered. Generally this is due to the following:

1. The criteria in Section B.1.a are invoked whenever possible to separate essential equipment from high-energy systems. In this case, breaks are arbitrarily postulated and a stress criterion is meaningless.

2. When it is not possible to separate high-energy piping from essential equipment, redundancy is provided or an evaluation is performed to ensure that the equipment will remain operable.

3. In areas in which high-energy pipe is routed, a sufficient number of breaks will always be postulated such that the effects of jet impingement, pipe whip, environment, etc., which

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result will envelop any intermediate or additional cracks.

The following discussion shows that for all areas of the plant, an additional criterion to postulate cracks is only repetitive and will not improve the safety of the plant

<u>High-energy piping not in the reactor building</u>
High-energy pipe is not routed near systems, components, or structures essential to safe shutdown in areas other than the reactor building. For example, there is a significant amount of high-energy piping located in the turbine building; however, there is no essential equipment located there which could compromise the safety of the plant. This piping actually meets the criteria of Section B.1.a where breaks are arbitrarily postulated to ensure separation of high-energy piping and essential equipment. It is therefore concluded that this will not degrade the safety of the plant.

<u>High-energy piping in the reactor building (excluding primary containment and containment penetration areas)</u>
Excluding the main steam tunnel piping, the only systems which qualify as high-energy piping in secondary containment are the RWCU, SLC, CRD, and RCIC systems. Routing of these systems has been controlled so that they are located in well-defined areas (i.e., RCIC pipe chase and turbine room, RWCU pump room, valve room, demineralizer room, heat exchanger room, and pipe chases). The walls of these compartments have been designed for jet impingement loads using a worst-case condition applied at any location. The compartments have also been evaluated for environmental, flood, pressure, etc., effects using the worst-case condition. Breaks in these areas are often arbitrarily postulated, and imposing additional criteria will not really enhance safety. It is therefore concluded that this will not degrade the safety of the plant.

Furthermore, the environmental effects of cracks in high-energy piping are enveloped by the effects of postulated cracks in moderate-energy systems. As discussed in Appendix 3C, all safety-related equipment in the reactor building is reviewed to ensure either operability or functional redundancy, where required, under environmental

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effects of spray from a crack in the RHR system piping. The resultant environment is equal to or is more severe than the effects of high-energy system piping cracks for both spray and flooding considerations. Therefore, a separate evaluation of high-energy crack environments is not required.

In the main steam tunnel, the effects of jet impingement will govern all cases assuming a minimum break criterion; therefore, this will not degrade the safety of the plant <u>Primary containment</u> If the primary containment piping were designed so that pipe stress results indicated that all high-energy systems required a minimum number of breaks to be postulated, approximately 100 breaks would be considered. In light of the separation between the high-energy systems in primary containment, it is reasonable to assume that these high-energy breaks will always govern. Any equipment, systems, or structures must be designed for the extreme environment in primary containment regardless of its particular location. Electrical equipment is routed in conduit or suitable housing so that it is not exposed to the open environment. The combination of separation and redundancy (the preferred method of protection) is also integral to components and piping routed in the primary containment This is verified in the jet impingement evaluation where breaks are postulated at various elevations and azimuths. Additional investigation is only repetitive. It is therefore concluded that this will not degrade the safety of the plant.

<u>Difference 2</u> Section B.1.c.1.d states that "if intermediate break locations cannot be determined by (b), (B.1.c.1.b) and (c), (B.1.c.1.c) above, two highest stress locations based on equation (10) should be selected." Unit 2 has eliminated arbitrary intermediate breaks (AIBs) in accordance with the intent of GL 87-11.

<u>Discussion</u> Per review of GL 87-11, dated June 19, 1987, and NUREG-1061 Volumes 3 and 5, it is reasonable to conclude that mechanical pipe rupture protection against AIBs in all systems is no longer required.

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Difference 3 Section B.1.c.4 states that "if a structure separates a high energy line from an essential component, the separating structure should be designed to withstand the consequences of the pipe break in the high energy line which produces the greatest effect at the structure irrespective of the fact that the above criteria might not require such a break location to be postulated." Unit 2 design structures withstand the consequence of pipe breaks postulated at locations in accordance with Sections B.1.c.1, B.1.c.2, and B.1.c.3.

Discussion A systematic logical method must be used to evaluate the effects of pipe breaks in order to address a finite number of potential load cases. By assuming breaks at highly stressed locations and by requiring a minimum number of locations to be selected, a reasonable margin of safety will evolve.

Requiring breaks to be postulated based on structural capability is not prudent and does not enhance the safety of the plant. Several points are:

1. Pipe whip loadings are very sensitive to the distance over which unrestrained whip could occur, piping geometry, and break orientation. An infinite number of cases would require consideration particularly if splits are arbitrarily postulated along the length of the pipe. Jet impingement does not have this problem since the load is distributed over a reasonable area. However, pipe whip requires evaluation of local effects, which is much more involved.

2. An excessive number of scab plates would be required on all structures which separate high energy and essential systems, thus causing an unreasonable number of scab plates to be installed.

3. By strengthening the weakest part of a structure, the next weakest part would then be the worst case. This is a perpetual cycle.

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4. Additional safety is not really obtained by evaluating the least likely events. Since pipe breaks themselves are extremely unlikely, it is reasonable to postulate them only at the higher stressed locations. Additionally, all walls in the proximity of high energy systems are evaluated for a reasonable number of pipe breaks simply due to the number of breaks which must be postulated using the stress criteria.

14. STANDARD REVIEW PLAN 3.6.2B, REVISION 1, JULY 1981 - DETERMINATION OF RUPTURE LOCATIONS AND DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

Difference 1 The method of determining pipe rupture locations inside containment differs in that Equation (12) or (13) is not considered, if Equation (10) is less than or equal to 3.0 Sm and the cumulative usage factor is less than 0.1.

Discussion This method is consistent with the previous revision of the SRP (November 24, 1975).

Difference 2 Criterion B.1.e identified in NUREG-0800 was not used.

Discussion This method was not part of the November 24, 1975, SRP which was the only guidance available during the period this work was being performed. The method used, cracks and breaks, is consistent with the SRP applicable at the time the work was performed.

15. STANDARD REVIEW PLAN 3.7.2A, REVISION 1 - SEISMIC SYSTEM ANALYSIS

Difference Additional seismicity of ±5 percent of the maximum building dimension at the level under consideration was not assumed.

Discussion Since the three-dimensional seismic models used in the dynamic analyses of Category I structures account for the torsional effects, including the effects of eccentricities between the centers of rigidity and the centers of mass of the structural components, the additional eccentricity of ±5 percent of the maximum building dimension is not considered necessary.

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16. STANDARD REVIEW PLAN 3.7.3B, REVISION 1 - SEISMIC SUBSYSTEM ANALYSIS

Difference For the determination of the number of earthquake cycles for nuclear steam supply system (NSSS) components and equipment other than piping, 10 equivalent peak operating basis earthquake (OBE) cycles are used, as opposed to the 50 OBE cycles specified in the acceptance criteria.

Discussion Fatigue evaluation due to SSE is not necessary since it is a faulted condition and thus not required by ASME Section III (FSAR Section 3.7B.3.2). The criterion requires that 50 OBE cycles be used, and for NSSS piping, 50 cycles are used. For other NSSS components and equipment, 10 equivalent peak OBE cycles are used (FSAR Section 3.7B.3.2). This 10-cycle approach has been approved by the NRC on the basis of equivalent levels of safety (letter from R. Bosnak [NRC] to R. Artigas [GE], Number of OBE Fatigue Cycles in the BWR NSSS Design, dated February 18, 1982).

17. STANDARD REVIEW PLAN 3.7.4, REVISION 1 - SEISMIC INSTRUMENTATION

Difference Seismic monitoring instrumentation surveillance frequency is not discussed.

Discussion The seismic monitoring instrument surveillance program has been incorporated in the Technical Specifications and Technical Requirements Manual Section 3.3.7.2.

18. STANDARD REVIEW PLAN 3.8.1, REVISION 1 - CONCRETE CONTAINMENT

Difference 1 An analysis was not performed to determine the ultimate capacity of the concrete containment.

Discussion In lieu of performing ultimate capacity analysis of the containment, the structural acceptance test performed prior to the plant operation for 1.15 times the design pressure is considered sufficient assurance for the adequacy of the analysis and design of the concrete containment.

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Difference 2 A design report was not prepared in accordance with Appendix C to SRP 3.8.4, Revision 1, for concrete containment.

Discussion In lieu of a design report, all the information relevant to the analysis and design of the concrete containment is provided in FSAR Section 3.8.1.

Difference 3 Compliance with RG 1.136 and ASME Section III, Division 2, was not used in designing the concrete containment and containment liner.

Discussion As stated in FSAR Table 1.8-1, RG 1.136, since the containment design precedes the issuance of RG 1.136 and ASME Section III, Division 2, it is not feasible to assure full compliance with these documents. While the loads and loading combinations are in accordance with Table CC-3230-1 of ASME III, Division 2, the acceptance criteria for stresses and strains and the procurement of materials for concrete and steel portions of the containment follows PSAR commitments. Consequently, the design, procurement, and construction of concrete and steel portions of the containment are in accordance with ACI 318, ACI 301, RG 1.94, and ASME Section III, Division 1, respectively. At the Construction Permit Stage this was accepted by the NRC as an adequate basis for the design, procurement, and construction of the containment.

19. STANDARD REVIEW PLAN 3.8.3, REVISION 1 - CONCRETE AND STEEL INTERNAL STRUCTURES OF STEEL OR CONCRETE CONTAINMENTS

Difference 1 Compliance with RG 1.142 and ACI 349-76 was not used in designing concrete internal structures.

Discussion As stated in FSAR Table 1.8-1, RG 1.142, since the design of internal structures precedes the issuance of RG 1.142 and ACI 349-76, it is not feasible to assure full compliance to these documents. Several major provisions of ACI 349-76 are identical to those of ACI 318-71 (and ACI 318-77) which was accepted for Unit 2 by the NRC at the Construction Permit Stage as an adequate basis for the design of Category I concrete structures. ACI 318-71 (and ACI 318-77) is used in designing the concrete internal structures.

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Difference 2 A design report as described in Appendix C to Section 3.8.4 for all internal structures was not prepared.

Discussion Although the information required by the design report is not provided in the format required by Appendix C of NUREG-0800, SRP 3.8.4, FSAR Section 3.8.3 provides the information necessary for evaluation of internal structures of containment.

20. STANDARD REVIEW PLAN 3.8.4, REVISION 1 - OTHER SEISMIC CATEGORY I STRUCTURES

Difference 1 Compliance with RG 1.142 and ACI 349-76 was not used in designing other Category I structures.

Discussion As stated in FSAR Table 1.8-1, RG 1.142, since the design of Category I structures precedes the issuance of RG 1.142 and ACI 349-76, it is not feasible to assure full compliance to these documents. Several major provisions of ACI 349-76 are identical to those of ACI 318-71 (and ACI 318-77) which was accepted by the NRC for the design of Unit 2 Category I concrete structures at the Construction Permit Stage. ACI 318-71 (and ACI 318-77) is used in designing Category I concrete structures.

Difference 2 A design report, as described in Appendix C, was not prepared for all Category I structures.

Discussion Although the information required by the design report is not provided in the format required by Appendix C, FSAR Section 3.8.4 provides the information necessary for evaluation of Category I structures.

Difference 3 Compliance to safety-related masonry wall criteria, as described in Appendix A to this SRP, was not required.

Discussion As described in FSAR Section 3.8.4.4, Unit 2 does not use masonry walls to support any safety-related structure, system, or component. However, removable, solid concrete blocks contained in position by structural steel supports and adjacent concrete structures are used in Category I structures to provide access for equipment

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removal and/or installation. Since the supports are designed to withstand all the possible loading combinations and remain in place, the solid concrete blocks cannot endanger adjacent structures, systems, or components. Hence, the criteria in Appendix A to this SRP are not applied to the concrete block designs. The concrete blocks are provided to satisfy the shielding requirements for the area.

21. STANDARD REVIEW PLAN 3.8.5, REVISION 1 - FOUNDATIONS

Difference 1 Compliance with RG 1.142 and ACI 349-76 was not used in designing foundations of Category I structures.

Discussion As stated in FSAR Table 1.8-1, since the design of foundations precedes the issuance of RG 1.142 and ACI 349-76, it is not feasible to assure full compliance to these documents. Several major provisions of ACI 349-76 are identical to those of ACI 318-71 (and ACI 318-77) which was accepted by the NRC to provide an adequate basis for the design of Category I concrete structures for Unit 2 at the Construction Permit Stage. ACI 318-71 (and ACI 318-77) is used in designing the foundations of Category I structures.

Difference 2 A design report, as described in Appendix C to Section 3.8.4, was not prepared for all foundations of Category I structures.

Discussion Although the information required by the design report is not provided in the format required by Appendix C of NUREG-0800, SRP 3.8.4, FSAR Section 3.8.5 provides the information necessary for evaluation of foundations of Category I structures.

22. STANDARD REVIEW PLAN 3.9.2A, REVISION 2 - DYNAMIC TESTING AND ANALYSIS OF SYSTEMS, COMPONENTS, AND EQUIPMENT

Difference 1 A list of snubbers on systems which experience sufficient thermal movement to measure snubber travel from the cold to the hot position is not provided.

Discussion This list will be developed prior to the detailed preoperational test program and included in an amendment to the FSAR.

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Difference 2 A description of the thermal motion monitoring program, i.e., verification of snubber movement, adequate clearances and gaps, including acceptance criteria and the manner in which motion will be measured, is not provided.

Discussion This will be developed prior to the detailed preoperational test program and included in an amendment to the FSAR.

Difference 3 A description of corrective action, to assure that a snubber which did not displace as predicted by analysis is operable, is not provided.

Discussion This will be addressed in the detailed preoperational test program.

Difference 4 The consideration of maximum relative displacements among supports of Category I systems and components is not described in this section.

Discussion Application to piping is discussed in FSAR Section 3.7A.3.8.3.

23. STANDARD REVIEW PLAN 3.9.2B, REVISION 2 - DYNAMIC TESTING AND ANALYSIS OF SYSTEMS, COMPONENTS, AND EQUIPMENT

Difference For the determination of the number of earthquake cycles for NSSS components other than piping, 10 equivalent peak OBE cycles are used. The SRP acceptance criteria require 50 cycles.

Discussion Fatigue evaluation due to SSE is not necessary since it is a faulted condition and thus not required by ASME Section III (FSAR Section 3.7B.3.2). The criterion requires that 50 OBE cycles be used, and for NSSS piping, 50 cycles are used. For other NSSS components and equipment, 10 equivalent peak OBE cycles are used (FSAR Section 3.7B.3.2). The 10-cycle approach has been approved by the NRC on the basis of equivalent levels of safety (letter from R. Bosnak [NRC] to R. Artigas [GE], Number of OBE Fatigue Cycles in the BWR NSSS Design, dated February 18, 1982).

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24. STANDARD REVIEW PLAN 3.9.3B, REVISION 1 - ASME CODE CLASS 1, 2, AND 3 COMPONENTS, COMPONENT SUPPORTS, AND CORE SUPPORT STRUCTURES

Difference Combination of loadings does not use the criteria in RG 1.124 and 1.130.

Discussion Load combination and acceptance criteria for Category I component supports are described in FSAR Sections 3.9B.3.1, 3.9B.3.4, and Table 3.9B-2. RG 1.124 and 1.130 apply respectively to Class 1 linear and Class 1 plate and shell component support designs. Their issue dates of January 1978 (RG 1.124, Revision 1) and July 1977 (RG 1.130) are after the Unit 2 Construction Permit docketing date requirement. However, the design utilizes ultimate strength temperature correlations of regulatory position C2 of these guides in regions adjacent to the pipe having high temperatures. Additionally, the critical buckling strength limits of ASME Section III, Appendix XVII, paragraph 2110(b), are observed in RG 1.124. Regulatory position C4 with alternate conservative collapse criteria for plates-shells is being used in lieu of regulatory position C3 in RG 1.130. The remaining design analysis criteria of these regulatory guides are considered to be adequately addressed by conservatisms present in the existing ASME Section III code.

25. STANDARD REVIEW PLAN 3.9.5B, REVISION 2 - REACTOR PRESSURE VESSEL INTERNALS

Difference 1 The design and construction of the core support structures do not conform to the requirements of subsection NG, Core Support Structures, of the ASME Code (Reference 5), and SRP Section 3.9.3.

Discussion Unit 2 core support structures were designed and purchased in 1971 prior to the issue of ASME Section III, subsection NG, in 1974. However, an earlier draft of ASME Section III, subsection NB, was used as a guide in developing the design of these supports. These criteria are presented in Section 3.9B.5.3. Subsequent to the issuance of ASME Section III, subsection NG, comparisons were made to assure that the pre-ASME Section III, subsection NG, design provides the equivalent level of safety as prescribed by ASME Section III, subsection NG, 1974.

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Difference 2 The design criteria, loading conditions, and analyses that provide the basis for the design of reactor internals other than the core support structures do not meet the guidelines of NG-3000.

Discussion Unit 2 reactor internals other than core support structures were designed and purchased prior to the initial issuance of ASME Section III, subsection NG. Design guidelines for these components and later safety comparisons against subsection NG criteria were selected as described for core support structures in criteria II.b under Difference 1.

26. STANDARD REVIEW PLAN 3.9.6, REVISION 2 - INSERVICE TESTING OF PUMPS AND VALVES

Difference The acceptance criteria for NUREG-0800 require that pumps and valves not categorized as Code Class 1, 2,or 3 but which are considered to be safety related be added to the inspection program.

Discussion The Unit 2 inservice testing program will conform to these criteria by meeting the relevant requirements set forth in GDC 37, 40, 43, 46, 54, and 10CFR50.55a.

27. STANDARD REVIEW PLAN 3.10, REVISION 2, JULY 1981 - SEISMIC AND DYNAMIC QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT

Difference The position for RG 1.148 is not provided in this section.

Discussion The Unit 2 degree of compliance with RG 1.148 is in FSAR Section 1.8.

28. STANDARD REVIEW PLAN 3.11, REVISION 2 - ENVIRONMENTAL QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT

Difference 1 The submittal of the environmental qualification document which demonstrates equipment environmental capability is not included.

Discussion The environmental qualification document is maintained as part of the Nine Mile Point Unit 2 Equipment Qualification Program. This document is maintained separately from the FSAR, and it is not considered a part of the FSAR.

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29. STANDARD REVIEW PLAN 4.2, REVISION 2 - FUEL SYSTEM DESIGN

Difference 1 Factors of 2 on stress or 20 on cycles are not used with the current method.

Discussion Design limits for fatigue failure are provided in GESTAR-II, Section A.4.2.1, and have been approved by the NRC.

Difference 2 Allowable fretting wear is not stated in the FSAR.

Discussion See GESTAR-II, Appendix A, Section A.4.2.1.1.3, and Section A.4.2.1.

Difference 3 Separate design limits for oxidation, hydriding, and corrosion buildup are not stated in the FSAR.

Discussion See GESTAR-II, Appendix A, Section A.4.2.1.

Difference 4 There is no limit for internal gas pressure stated in the FSAR.

Discussion See GESTAR-II, Appendix A, Section A.4.2.1. Current methodology has been approved by the NRC.

Difference 5 Allowable fretting wear is not stated in the FSAR.

Discussion See GESTAR-II, Appendix A, Section A.4.2.1.2.3.

Difference 6 There is no centerline melt criterion for abnormal operational events stated in the FSAR.

Discussion See GESTAR-II, Appendix A, Section A.4.2.1. (Reference subsections 2.4.2.5 and 2.4.1.1, GESTAR-II.)

Difference 7 A description of elastic strain limits is not included in the FSAR. There is no centerline melt criterion for abnormal operational events described in the FSAR.

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Discussion The 1 percent plastic strain criterion is applied to all abnormal operating events. No fuel melt criterion is applied. This methodology has been approved by the NRC. See GESTAR-II, Appendix A, Section A.4.2.1.

Difference 8 The fuel system description does not provide all the information discussed in the acceptance criteria.

Discussion The level of descriptive information and detail in the FSAR is consistent with that previously approved and accepted by the NRC. Quantitative information is provided in GESTAR-II, Chapters 2 and S.2, and is referenced in FSAR Section 4.2.

Difference 9 Surveillance of control rods for boron leaching is not provided in the FSAR.

Discussion Periodic reactivity testing of the control rods (beyond the beginning of cycle shutdown margin demonstration) is performed only if there is reason to suspect control absorber loss or other degradation of the control blades.

30. STANDARD REVIEW PLAN 4.4, REVISION 1 - THERMAL AND HYDRAULIC DESIGN

Difference Compliance with TMI Action Plan requirements (NUREG-0737) is not assessed in this section.

Discussion See FSAR Section 1.10, Tasks II.D.1, II.F.1, and II.F.2.

31. STANDARD REVIEW PLAN 4.5.1, REVISION 2 - CONTROL ROD DRIVE STRUCTURAL MATERIALS

Difference 1 Only those parts of the control rod drive (CRD) forming part of the primary pressure boundary are code materials.

Discussion Jurisdiction of ASME Section III does not extend to the nonpressure parts of the CRD. ASME materials are identified in the materials list of FSAR Section 4.5.1.1.

Difference 2 Some CRD structural materials were not purchased to code requirements, but there is no difference for tempering and aging temperatures.

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Discussion Noncode materials are not required to be purchased to code requirements. The materials specified were, however, selected for their compatibility with the reactor coolant. Tempering and aging are done according to standards which are discussed in FSAR Section 4.5.1.

32. STANDARD REVIEW PLAN 4.5.2, REVISION 2 - REACTOR INTERNAL AND CORE SUPPORT MATERIALS

Difference 1 ASME Section III, NG-2000, specifications were not used.

Discussion For core support and reactor internals, the material specifications given in ASME Section III, NG-2000, were not used. Article NG-2000 was not part of Section III at the time these materials were procured for Unit 2. All core support structures were fabricated from ASME- and ASTM-specified materials and designed using ASME Section III as a guide. The other reactor internals are noncoded and are fabricated from ASME or ASTM specification materials. Material requirements in the ASTM specifications are identical to the requirements given in the corresponding ASME specifications. The material specifications for Unit 2 reactor internal and core support materials are given in FSAR Section 4.5.2.1.

Difference 2 ASME Section III, NG-4000 and NG-5000, were not imposed.

Discussion The requirements of Articles NG-4000 and NG-5000 were not part of ASME Section III when fabrication welding was performed for Unit 2. As specified in FSAR Section 4.5.2.2., welding was performed to the requirements of ASME Section IX. Conformance to regulatory guides applicable to welding (i.e., RG 1.31, 1.34, 1.37, 1.44, and 1.71) is presented in FSAR Section 4.5.2.4.

Difference 3 ASME Section III, NG-2500 and NG-5300, were not imposed.

Discussion Articles NG-2500 and NG-5300 were not part of ASME Section III at the time the Unit 2 wrought seamless tubular products and fittings were procured. As contained in FSAR Section 4.5.2.3, wrought seamless tubular products for CRD guide tubes, CRD housings, and peripheral fuel

supports were supplied in accordance with applicable ASME material specifications. These specifications require a hydrostatic test on each length of tubing. No other nondestructive testing was specified for the tubes.

33. STANDARD REVIEW PLAN 5.2.1.1, REVISION 2 - COMPLIANCE WITH THE CODES AND STANDARDS RULE, 10CFR50.55a

Difference Differences exist between the Unit 2 design and RG 1.26, Quality Group Classification and Standards.

Discussion Justification for all differences listed in Table 3.2-1 are discussed in the notes to the table.

34. STANDARD REVIEW PLAN 5.2.2, REVISION 2 - OVERPRESSURE PROTECTION

Difference TMI Tasks are not discussed in this section.

Discussion NUREG-0737, Task II.D.3, is discussed in FSAR Sections 1.10 and 5.4.12.

35. STANDARD REVIEW PLAN 5.2.3, REVISION 2 - REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Difference 1 Material Specifications - Part of the RCPB materials comply with ASME Section II, Parts A and C, only.

Not all ASME Code cases used are listed in RG 1.84 and 1.85.

Discussion Section 5.2.3.1 and Table 5.2-5 list components and their material specifications. These specifications comply with ASME Section II, Parts A and C, and are augmented with ASME Section III, Code Cases 1562 and 1572, and Code cases approved by RG 1.84 and 1.85.

Code Cases 1141-1, 1332-6, 1361-2, 1557-2, 1620, and N-1588, which are imposed by RG 1.84 and 1.85, were used as noted in FSAR Table 5.2-1. Other Code cases used but not imposed by these regulatory guides are 1562 and 1572. These Code cases have been annulled and incorporated into ASME Section III.

Difference 2 The FSAR does not address the qualification of welding procedures at the minimum preheat.

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Discussion FSAR Section 5.2.3.3.2 indicates that components were either held for an extended time at preheat temperature to assure removal of hydrogen or were maintained at preheat temperature until postweld treatment. Minimum preheat and maximum interpass temperatures were specified and monitored.

Difference 3 Some ferrite tubular products do not meet all requirements of RG 1.66 and ASME Section III, paragraph NB-2550.

Discussion See FSAR Section 5.2.3.3.3. Nondestructive examination of ferrite tubular products met existing ASME Section III and 10CFR50 criteria at order placement, which in some cases predated RG 1.66. CRD housing tubes do meet ASME Section III, paragraph NB-2550.

Difference 4 RG 1.44 was not applied completely by the Unit 2 project design basis for the NSSS.

Discussion For NSSS components, alternate criteria for sensitization controls of stainless steel which satisfy NUREG-0313 are discussed in FSAR Section 5.2.3.4.

Difference 5 The NSSS QA program complies with RG 1.37 except for Section 5, paragraph G, which recommends that local rusting on corrosion-resistant alloys be removed by mechanical means.

Discussion GE Topical Report NEDO-11209 (accepted by the NRC) describes the NSSS QA program and does not preclude the use of other than mechanical means for local rust removal.

Difference 6 Some austenitic tubular products were procured prior to the creation of ASME Section III, paragraph NB-2550.

Discussion See FSAR Section 5.2.3.3.3 and the assessment of criterion II.3.c of this SRP for positions on ASME Section III, paragraph NB-2550, requirements.

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36. STANDARD REVIEW PLAN 5.3.1, REVISION 1 - REACTOR VESSEL MATERIALS

Difference 1 Special Methods for Nondestructive Examination - Ultrasonic examination methods meet ASME Section XI, 1980 Edition through the Winter 1980 Addenda, Appendix I, rather than ASME Section III requirements.

Discussion FSAR Section 5.3.1.2 describes radiographic examination, which is performed on all pressure-containing welds in accordance with requirements of ASME Section III, subsection NB-5320. FSAR Section 5.3.1.3 indicates that materials and welds on the RPV were examined by methods which meet ASME Section III requirements. Special ultrasonic examination meeting ASME Section XI, 1980 Edition through the Winter 1980 Addenda, Appendix I, requirements using manual techniques were used. Acceptance standards were equal to or greater than those required by ASME Section XI, 1980 Edition through the Winter 1980 Addenda.

Difference 2 The NSSS QA program complies with the referenced regulatory guides except for Section 5, paragraph 6, of RG 1.37, which recommends that local rusting on corrosion-resistant alloys be removed by mechanical means.

Discussion GE Topical Report NEDO-11209 (accepted by the NRC) describes the NSSS QA program and does not preclude the use of other than mechanical means for local rust removal.

37. STANDARD REVIEW PLAN 5.4.6, REVISION 2 - REACTOR CORE ISOLATION COOLING SYSTEM (BWR)

Difference TMI action items are not discussed in this section.

Discussion See FSAR Section 1.10 for NUREG-0737.

38. STANDARD REVIEW PLAN 5.4.8, REVISION 2 - REACTOR WATER CLEANUP SYSTEM

Difference 1 All RWCU system components are not drained and vented through closed systems.

Discussion Vents and drains associated with the pumps and the regenerative and nonregenerative heat exchangers are routed to the reactor building equipment drain system

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through open drains which are vented to secondary containment atmosphere. The pumps and heat exchanger vents are used to vent the equipment when filling the system. The drains are used to empty the components prior to maintenance.

The temperature of the water will be low enough during these draining and venting operations that the possibility of airborne contamination will be minimal. Therefore, the routing of these lines to an open drain connection is acceptable.

<u>Difference 2</u> Evaluation of compliance with the Technical Specifications for water chemistry parameter limits is not provided.

<u>Discussion</u> Reactor water purity will be maintained by the system to yield effluent water in accordance with the requirements of RG 1.56 (FSAR Section 5.4.8.1.2) and the specifications for water chemistry within limits described in the TRM.

39. <u>STANDARD REVIEW PLAN 6.1.2, REVISION 2 - PROTECTIVE COATING SYSTEMS (PAINTS) - ORGANIC MATERIALS</u>

<u>Difference</u> For a small fraction of the exposed surfaces in the drywell, the recommendation of RG 1.54 is not met.

<u>Discussion</u> See FSAR Sections 6.1.2.1 and 6.1.2.2. Protective coatings are generally not used in the suppression pool. The majority of the exposed surfaces within the drywell (i.e., primary containment lines, drywell head, biological shield wall, structural steel, cranes, pipe rupture restraints, pipe supports, piping, and concrete) are coated with materials qualified in accordance with ANSI N101.2 and applied in accordance with RG 1.54. The balance of the exposed surfaces within the drywell (i.e., valve bodies, hand wheels, electrical and control panels, loudspeakers, and emergency light cases), constituting a small fraction of the total exposed surfaces, do not satisfy RG 1.54 conditions.

40. <u>STANDARD REVIEW PLAN 6.2.1.1.c, REVISION 4, JULY 1981, APPENDIX I TO STANDARD REVIEW PLAN 6.2.1.1.c, REVISION 1, JULY 1981 - PRESSURE-SUPPRESSION TYPE BWR CONTAINMENTS</u>

<u>Difference 1</u> Peak calculated temperature for the wetwell airspace exceeds the design temperature of the suppression pool.

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Discussion Peak calculated containment pressure and deck differential pressure are within design limits. Drywell calculated environment temperature is below its design value. However, following the steam bypass transient, the atmospheric temperature in the suppression chamber is greater than 212°F (superheated). For a small-break LOCA with steam bypass, the temperature is determined to be approximately 250°F. Any Category 1 equipment in the suppression chamber will be qualified to the maximum envelope value of 270°F, which has been specified in environmental qualification documents. However, the structure temperature, i.e., steel liner, remains below the saturation temperature of the suppression chamber atmosphere for the duration of the transient. Since the liner temperature is below 212°F, the design temperature of the suppression chamber structure is not exceeded.

Difference 2 Suppression chamber spray is not autoactuated following a LOCA.

Discussion One of the SRP requirements concerns the automatic suppression chamber spray limiting containment pressure to 45 psig considering steam bypass. Analysis for Unit 2 shows that containment spray is not necessary for the first 30 min following a LOCA; therefore, manual spray is justified. This will eliminate the potential for inadvertent spray due to the malfunction of an automatic control.

Difference 3 A redundant position indicator for each vacuum relief valve and an alarm for vacuum breaker valves are not provided.

Discussion Each vacuum breaker flow path has two relief valves mounted horizontally in series to ensure a leak-tight boundary. Three flow paths are required for the vacuum breaker design basis; however, four flow paths (eight valves) are provided. Each vacuum relief valve is provided with three position-sensing devices mounted 120 degrees apart around the circumference of each disc. One of the position-sensing devices is mounted at the bottom of the disc. These devices are designed such that all three positions must be within 0.05 in of the full-closed position before a closed signal can be initiated. Total detectable opening for the vacuum breakers is $\leq$0.044 ft^2 vs. the allowable bypass leakage capacity of 0.05 ft^2, thus providing adequate sensitivity. Although redundant

position indication does not exist on each vacuum relief valve, redundancy is achieved due to redundant valves in each flow path. Indication in the control room is achieved by red/green lights.

Difference 4 Visual inspection at each refueling outage for vacuum relief valves and piping is not described.

Discussion 4 This is addressed in plant programs.

Difference 5 Vacuum breaker operability test at monthly intervals is not described.

Discussion 5 This is addressed in the Technical Specification.

41. STANDARD REVIEW PLAN 6.2.1.2, REVISION 2, JULY 1981 - SUBCOMPARTMENT ANALYSIS

Difference The acceptable model for subcompartment initial conditions is to assume air at the maximum allowable temperature, minimum absolute pressure, and zero percent relative humidity.

One of the Unit 2 annulus pressurization analyses assumes 20 percent relative humidity instead of zero percent.

Discussion The governing case for the design of the annulus considers zero percent relative humidity; therefore, Unit 2 meets the intent of the acceptance criteria.

42. STANDARD REVIEW PLAN 6.2.1.3, REVISION 1, JULY 1981 - MASS AND ENERGY RELEASE ANALYSIS FOR POSTULATED LOCAs

Difference The ability of the containment and its associated systems, including subcompartments, to withstand calculated pressure and temperature conditions resulting from any LOCA without exceeding design temperature is not discussed in this section.

Discussion See discussion for SRP 6.2.1.1.c (steam bypass temperature of wetwell).

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43. STANDARD REVIEW PLAN 6.2.2, REVISION 3, JULY 1981 - CONTAINMENT HEAT REMOVAL SYSTEMS

Difference The spray drop efficiency calculation is not provided.

Discussion An analysis of the spray drop thermal effectiveness was not performed due to the unavailability of drop size test data from the nozzle manufacturer. When the required drop size data become available, the spray thermal effectiveness will be calculated by the method referenced in this SRP.

43.1 STANDARD REVIEW PLAN 6.2.5, REVISION 2 - COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Difference The interval between ECCS initiation and establishment of containment hydrogen monitoring is increased from 30 min to 90 min.

Discussion Control Room Operators use the hydrogen monitoring to establish hydrogen control measures should they become necessary after a LOCA. However, these measures are not needed for the first 36 hr after a LOCA, and the actions required to establish containment hydrogen monitoring distract the Operators from more important tasks during the early phases of an accident. The 60-min extension allows the system to be placed in a standby mode during normal operation to improve system reliability, while ensuring that hydrogen monitoring will be established well before hydrogen control measures are required.

44. STANDARD REVIEW PLAN 6.2.7, REVISION 0 - FRACTURE PREVENTION OF CONTAINMENT PRESSURE BOUNDARY

Difference Not all of the Class 2 piping and/or components (valves) have had actual impact testing performed.

Ferritic materials of construction for the containment pressure boundary have been toughness tested as follows:

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1. All ferritic material of the primary containment liner (e.g., drywell and suppression pool liner plate, equipment and personnel hatches, drywell head, penetration sleeves, etc.) requiring notch toughness have been Charpy impact tested and conform to NE-2300 of ASME Section III. This information may be found in FSAR Section 3.8.1, specifically Item 3.8.1.6.2.

2. Class 1 ferritic process piping has been impact tested and conforms to NB-2300 of ASME Section III.

Discussion Class 2 ferritic process piping has not been impact tested, except for that portion included in the penetration assembly which penetrates the containment liner. It has been impact tested and conforms to NB-2300 of ASME Section III.

An initial review indicates that similar construction materials have been used on those items which were not subjected to actual impact testing. This indicates that inherent toughness may be substantiated.

45. STANDARD REVIEW PLAN 6.3, REVISION 1 - EMERGENCY CORE COOLING SYSTEM

Difference The requirements of the following Task Action Plans are not addressed in this section:

1. Task Action Plan II.B.8 of NUREG-0718 (Reference 14).

2. Task Action Plan III.D.1.1 of NUREG-0694 and NUREG-0718.

3. Task Action Plan II.E.2.1 of NUREG-0737.

4. Task Action Plan II.K.3(10) of NUREG-0737 and NUREG-0718.

5. Task Action Plan II.K.3(15) of NUREG-0737 and NUREG-0718.

6. Task Action Plan II.K.3(18) of NUREG-0737 and NUREG-0718.

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7. Task Action Plan II.K.3(21) of NUREG-0737 and NUREG-0718.

Discussion Items 1, 2, 5, 6, and 7 are discussed in FSAR Section 1.10. Items 3 and 4 are not applicable to Unit 2.

46. STANDARD REVIEW PLAN 6.5.1, REVISION 2, JULY 1981 - ENGINEERED SAFETY FEATURES ATMOSPHERE CLEANUP SYSTEMS

Difference Exception is taken with compliance to RG 1.52.

Discussion See FSAR Table 1.8-1.

47. STANDARD REVIEW PLAN 8.3.1, REVISION 2 - AC POWER SYSTEMS (ONSITE)

Difference The Division III (HPCS) standby diesel generator (GM-EMD) is provided with a standard-duty turbocharger mechanical drive gear assembly.

Discussion The Division III standby diesel generator is retrofitted with a heavy-duty turbocharger drive gear assembly.

48. STANDARD REVIEW PLAN 9.1.3, REVISION 1 - SPENT FUEL POOL COOLING AND CLEANUP SYSTEM

Difference The acceptance criteria of Section II.1.d.(4) require computation of decay heat loads based on one refueling load after 150 hr decay, plus one refueling load after 1 yr decay. FSAR Section 9.1.3.2 describes the conditions for the spent fuel heat load as one refueling load after 48 hr decay plus additional refuelings decayed in multiples of fuel cycle length after reactor shutdown.

Discussion The decay times used to compute the spent fuel heat loads are consistent with expected operating procedures and refueling cycles for Unit 2.

49. STANDARD REVIEW PLAN 9.1.5, REVISION 0 - OVERHEAD HEAVY LOAD HANDLING SYSTEM

All material relating to this subject is in Section 9.1.4.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

50. STANDARD REVIEW PLAN 9.2.2, REVISION 1 - REACTOR AUXILIARY COOLING WATER SYSTEM

Difference 1 Task II.K.2.16 of NUREG-0718 and Task II.K.3.25 of NUREG-0737, as they relate to loss of cooling water to reactor coolant pump seals, are not addressed in this section.

Discussion NUREG-0718 is not applicable to Unit 2. It is applicable to applicants for construction permit or manufacturing license only.

Task II.K.3.25 is addressed in FSAR Section 1.10.

Difference 3 The ability of the reactor coolant pumps to withstand a complete loss of cooling water for 20 min is not demonstrated by testing.

Discussion An analysis was used to demonstrate that the cooling water systems have been designed such that cooling water will be provided whenever it is needed.

51. STANDARD REVIEW PLAN 9.2.3, REVISION 2 - DEMINERALIZED WATER MAKEUP SYSTEM

Difference Acceptance Criterion II, 1, is not addressed.

Discussion Unit 2 is in compliance with SRP 9.2.3, Acceptance Criterion II, 1, although it is not addressed. All makeup water system piping in the reactor building is seismically analyzed.

52. STANDARD REVIEW PLAN 9.3.2, REVISION 2 - PROCESS AND POST-ACCIDENT SAMPLING SYSTEMS

Difference 1 The post-accident sampling system is not completely addressed in Section 9.3.2.

Discussion Additional information on the post-accident sampling system is provided in Task II.B.3.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

53. STANDARD REVIEW PLAN 9.4.1, REVISION 2, JULY 1981 - CONTROL ROOM AREA VENTILATION SYSTEM

Difference Unit 2 does not meet the guidance of RG 1.52 and 1.140.

Discussion Unit 2 complies with the intent of RG 1.52 and 1.140 (paragraph c of these guides) through the alternate approaches discussed in FSAR Section 1.8.

54. STANDARD REVIEW PLAN 9.4.2, REVISION 2, JULY 1981 - SPENT FUEL POOL AREA VENTILATION SYSTEM

Difference Unit 2 does not meet the guidance of RG 1.52 and 1.140.

Discussion Unit 2 complies with the intent of RG 1.52 and 1.140 (paragraph c of these guides) through the alternate approaches discussed in FSAR Section 1.8.

55. STANDARD REVIEW PLAN 9.4.3, REVISION 2, JULY 1981 - AUXILIARY AND RADWASTE AREA VENTILATION SYSTEM

Difference Unit 2 does not meet the guidance of RG 1.140.

Discussion Unit 2 complies with the intent of RG 1.140 (paragraph c) through the alternate approach discussed in FSAR Section 1.8.

56. STANDARD REVIEW PLAN 9.4.5, REVISION 2, JULY 1981 - ENGINEERED SAFETY FEATURE VENTILATION SYSTEM

Difference Unit 2 does not meet the guidance of RG 1.52.

Discussion Unit 2 complies with the intent of RG 1.52 (paragraph c) through the alternate approach discussed in FSAR Section 1.8.

57. STANDARD REVIEW PLAN 9.5.1, REVISION 3, JULY 1981 - FIRE PROTECTION PROGRAM (FIRE PROTECTION SYSTEM)

Deviations to BTP CMEB 9.5-1
Attached to Standard Review Plan 9.5.1
Fire Protection Program

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

Difference 1 Section C.1.c.(3) states that "the fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe shutdown following the safe shutdown earthquake (SSE).

Discussion Unit 2 standpipe and hose connection design is in accordance with Appendix A (dated August 1976) to BTP 9.5-1 (dated May 1, 1976) and Appendix R to 10CFR50, and is not seismically qualified.

The design does not contemplate simultaneous earthquake and fire conditions; therefore, this requirement was not incorporated into the design. Further, justification is that Unit 2 is not in an area of high seismic activity.

Difference 2 Section C.5.a(3)(b) of Unit 2 design incorporates fire boot-type penetration seals (approximately 200 of 11,000 fire-rated seals) for which temperature levels on the unexposed side reached 393°F during the acceptance test.

Discussion Fixed combustibles potentially within close proximity have ignition temperatures of >500°F. Cables are generally installed in raceways (i.e., conduit or cable trays).

Difference 3 Section C.5.a(5) - Unit 2 fire doors are administratively supervised to verify that they are in the closed position.

Discussion Fire doors are maintained in the closed position.

The doors are administratively verified to be in the closed position on a daily basis. Additionally, fire doors in areas protected by total-flooding CO_2 systems are provided with heavy-duty door closures. Halon 1301 suppression systems are used in computer rooms and control rooms. Doors to these areas are inherently supervised by the occupants in the area, in addition to the daily inspection, to verify that the doors are in the proper position.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

Difference 4 Section C.5.a(14) - Unit 2 floor drains are conservatively sized and are in accordance with the National Plumbing Code. They were not sized based on firefighting water flows.

Discussion Unit 2 fixed water suppression systems incorporate the use of closed-heads and closed-water spray nozzles, which inherently limit the amount of water discharged to the area of involvement during a fire. Refer to Section 9A.3.5.1.12 for the results of an evaluation completed to determine the effects of firefighting water flows on floor drains.

Difference 5 Section C.5.b.(2) - Credit is taken in the Unit 2 reactor building for separation of cables, equipment, and associated circuits of redundant trains of safe shutdown equipment by a horizontal distance of more than 20 ft. Fire detection and automatic suppression systems are provided in the zone. Nonsafe shutdown-related cable trays traverse the 20-ft zone.

Discussion Fire detection, automatic area suppression, and automatic cable tray suppression systems are provided for the cables in this zone in accordance with Section 9A.3.5.5.3. The cables are IEEE-383 qualified. Non-critical cables (e.g., communications cables) in this zone meet or exceed the flame propagation requirements of IEEE-383.

Difference 6 Section C.5.e.(2) - Unit 2 safety-related cable trays are provided with ionization-type detectors in lieu of line-type and ionization detectors. Unit 2 safety-related cable trays are provided with closed-head preaction sprinkler systems in lieu of open-head deluge or open directional spray nozzle systems.

Discussion Safety-related cable trays are provided with ionization-type smoke detectors which provide an earlier warning system than line-type heat detectors. Safety-related cable trays that are not accessible for manual firefighting are protected by zoned automatic closed-head reaction sprinkler systems. Water spray systems that incorporate the use of open directional spray

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nozzles discharge an excessive amount of water in protected areas, requiring substantially larger drainage and processing capabilities than areas protected by sprinkler systems which minimize the potential for damage to safety-related structures and components.

<u>Difference 7</u> Section C.5.g(1) - Unit 2 emergency lighting capability is provided by means other than individual 8-hr battery supplies.

<u>Discussion</u> Areas which must be manned during safe shutdown will be supplied with 8-hr battery-packs for access and egress lighting.

<u>Difference 8</u> Section C.5.g.(3) - The Unit 2 emergency communications system is not independent of the plant communication system.

<u>Discussion</u> Fixed emergency communications systems independent of normal plant communications systems are not necessary because:

1. The systems are connectable to uninterruptible power sources, which provide reliability during emergency conditions.
2. In case of total loss of power to all communication systems, the sound-powered communication (SPC) system can be utilized.
3. The system is set up as described in Section 9.5.2.
4. The system and important components are supervised.

<u>Difference 9</u> Section C.6.a.(3) - The fire detector spacing criteria for Unit 2 meet the intent of NFPA 72E.

STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

Discussion NFPA 72E recommends one detector per bay for beam depth greater than 8 in and bay width greater than 8 ft. NFPA 72E does not address beam depth greater than 8 in and bay width less than 8 ft. In this situation, the Unit 2 design incorporates one detector for every other bay mounted on the bottom flange of structural steel.

Difference 10 Section C.6.c.(4) - Unit 2 design does not incorporate a cross-connection to the SWP system for firefighting capability post-SSE.

Discussion Standpipes and hose connections for manual firefighting are seismically supported in safety-related areas and in areas containing safety-related equipment. The design bases do not contemplate simultaneous earthquake and fire conditions; therefore, this requirement was not incorporated into the design. Further justification is that Unit 2 is not in an area of high seismic activity.

Difference 11 Section C.7.a.(1), part (c) - During normal operation, the Unit 2 design does not incorporate the use of general area fire detection in the primary containment.

Discussion The Unit 2 containment is inerted during normal operation.

Difference 12 In general, Section C endorses the use of the National Fire Protection Association (NFPA) standards. Unit 2 deviates from a number of these NFPA standards.

Discussion Each Unit 2 deviation to the NFPA standards is described and justified in Table 9.5-3.

Difference 13 Section C.7.b - Unit 2 design incorporates the use of carpet in the control room.

Discussion Carpet exceeds NFPA 101, Class I, interior floor finish requirements and is required to satisfy human factors guidelines.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

58. STANDARD REVIEW PLAN 10.3, REVISION 2 - MAIN STEAM SUPPLY SYSTEM

Difference Acceptance Criterion II, 2, is not addressed in Section 10.3 with respect to internally- or externally-generated missiles.

Discussion Unit 2 complies with this criterion as discussed in FSAR Section 3.5.1.

59. STANDARD REVIEW PLAN 10.4.2, REVISION 2 - MAIN CONDENSER EVACUATION SYSTEM

Difference RG 1.33 and 1.123 are not addressed in this section.

Discussion RG 1.33 and 1.123 are discussed in Section 1.8.

60. STANDARD REVIEW PLAN 10.4.3, REVISION 2 - TURBINE GLAND SEALING SYSTEM

Difference RG 1.33 and 1.123 are not addressed in this section.

Discussion RG 1.33 and 1.123 are discussed in Section 1.8.

61. STANDARD REVIEW PLAN 11.2, REVISION 2 - LIQUID WASTE MANAGEMENT

Difference The Unit 2 position on RG 1.143 is not addressed in this section.

Discussion The Unit 2 project complies with RG 1.143 through the alternate approach discussed in Section 1.8.

62. STANDARD REVIEW PLAN 11.3, REVISION 2 - GASEOUS WASTE MANAGEMENT SYSTEMS

Difference The Unit 2 position on RG 1.143 is not addressed in this section.

Discussion The Unit 2 project complies with RG 1.143 through the alternate approach discussed in Section 1.8.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

63. STANDARD REVIEW PLAN 11.3, REVISION 0, BRANCH TECHNICAL POSITION ETSB 11-5 - POSTULATED RADIOACTIVE RELEASES DUE TO A WASTE GAS SYSTEM LEAK OR FAILURE

Difference A comparison of the main parameters of the waste gas system event analysis, as presented in this SRP and those actually used in FSAR Section 15.7.1, is provided below.

Parameter	NUREG-0800 BTP ETSB 11-5	FSAR Section 15.7.1
Accident/event	Bypass of charcoal delay units, release of underplayed offgas activities	Failure of charcoal delay beds, release of total bed activity.
Source term	7 x normal operation source term 7x50.000 uCi/s = 350,000 uCi/s	100 uCi/S/MWt (100x4.068 MWt) = 406.800 uCi/s
Source term decay time	30 min	30 min
Isotopes considered	Xe. Kr. Ar	Xe, Kr
Holdup time on charcoal beds	Not applicable	Xe - 249 days Kr - 333 hr
Release point	Ground level	Ground level
Duration of release	2 hr	2 hr
Value of X/Q	5% overall site short term	.5% maximum sector short term
Duration of exposure	2 hr	2 hr
Dose calculations	Semi-infinite cloud	Semi-infinite cloud
Exposure limit	<0.5 Rem total body	<5 Rem whole body (calculated .39 Rem) <30 Rem Beta (calculated .31 Rem)

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

Discussion The analysis of the failure of the offgas system, provided in Section 15.7.1, is more conservative than the analysis proposed in this SRP, in terms of duration, X/Q, and transit time. Therefore, the existing analysis envelops that proposed by BTP ETSB 11-5.

64. STANDARD REVIEW PLAN 12.2, REVISION 2 - RADIATION SOURCES

Difference 1 Shielding and ventilation design fission product source terms were not developed using these bases:

1. An offgas rate of 100,000 uCi/sec after 30 min delay for BWRs.

2. 0.25 percent fuel cladding defects for PWRs.

Discussion The general basis for the shielding design is stated in Section 12.2.1.1. Sections 12.2.1.2 through 12.2.1.5 provide source data that were used in shielding designs. Sources of airborne radiation to be considered in ventilation design are discussed in Section 12.2.2. Criterion (1) is discussed in Section 11.1, and criterion (2) does not apply.

65. STANDARD REVIEW PLANS 12.3 AND 12.4, REVISION 2 - RADIATION PROTECTION DESIGN FEATURES

Difference 1 The following items required by NUREG-0800, Section II.1, are not presented in the FSAR.

1. Access control to spent fuel transfer canal should be more stringent than that required by 10CFR20.203.

2. All accessible portions of the spent fuel transfer canal that are capable of having radiation levels greater than 100 rads/hr shall be shielded during fuel transfer.

3. Removable shielding may be used (for Item b) but must be explicitly marked. Local audible and visible alarming radiation monitors must be installed to alert personnel if the temporary shielding is removed during fuel transfer operations.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

4. All accessible portions of the spent fuel transfer tube shall be clearly marked with a sign stating that potentially lethal radiation fields are possible during fuel transfer.

5. Similar precautions to those described in Items a through d shall also apply to any other radiation source having radiation levels higher than 100 Rem/hr.

Discussion

1. Because of the procedures and shield design described below, access control in accordance with 10CFR20 is considered to be adequate.
2. A portable shield or access control will be used to limit dose rates in areas of the drywell accessible during fuel transfer to <20 mRem/hr.

3. Refueling procedures will either mandate the placement of the radiation shield or implement access controls before fuel transfer operations. Portable monitors will be used to alarm audibly and visibly in the drywell if the portable shield is not installed or is removed during fuel transfer.

4. Not applicable to Unit 2 design.

5. Precautions similar to those described above may also be taken for other radiation sources having radiation levels in excess of 100 Rem/hr.

Difference 2 Area radiation monitors are required by NUREG-0800, paragraph II.4.A.3, to remain on-scale when measuring dose rates during accidents and anticipated operational occurrences. A description of vital area monitoring has not been provided in Section 12.3.4.

Discussion Post-accident vital area monitors meet the criterion of NUREG-0800, paragraph II.4.A.3, and will be addressed in an amendment to FSAR Section 12.3.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

66. STANDARD REVIEW PLAN 12.5, REVISION 2 - OPERATIONAL RADIATION PROTECTION PROGRAM

Difference 1 No personnel count rate meters are provided.

Discussion The use of count rate meters on protective clothing will provide little, if any, additional radiation protection in view of the extensive personnel monitoring that will be implemented.

Difference 2 TLDs are processed quarterly.

Discussion Although Unit 2 does conform to Regulatory Guide 8.3, in 1987 10CFR20 was amended to require all licensees to have personnel dosimetry devices that are utilized to comply with NRC regulations processed by processors that have been accredited by the National Voluntary Laboratory Accreditation Program (NVLAP) of the National Bureau of Standards. In the statement of consideration for this amendment, the NRC specified that dosimetry processors would demonstrate compliance with ANSI N13.11-1983 through testing. Nine Mile Point Dosimetry Facility is accredited by NVLAP to process TLDs by virtue of actual demonstration of compliance with ANSI N13.11-1983 through testing. Based on "fade" studies, processing TLDs quarterly instead of monthly does not affect the dosimetry facility's NVLAP accreditation and complies with 10CFR20.

67. STANDARD REVIEW PLAN 13.4, REVISION 2 - OPERATIONAL REVIEW

Difference Independent review is not performed by an ISEG.

Discussion Independent review is performed by the NSRB and the Onsite Technical Services Group, as described in Section 1.10 and Chapter 13. The approach given meets the intent of the requirements stated.

68. STANDARD REVIEW PLAN 14.2, REVISION 2 - INITIAL PLANT TEST PROGRAM

Difference The test abstracts contain significant parameters but do not include plant performance characteristics.

Discussion The preoperational test descriptions, which will be available for NRC review at least 60 days before the test is to be run, will include plant performance characteristics.

69. STANDARD REVIEW PLANS 15.3.3 AND 15.3.4, REVISION 2 - REACTOR COOLANT PUMP ROTOR SEIZURE AND REACTOR COOLANT PUMP SHAFT BREAK

Difference Accident analysis of these faulted events does not include the assumption of turbine trip and coincident LOOP and coastdown pumps.

Discussion The consequences of this combination would be less severe than the transient analyzed in FSAR Section 15.2.6. The turbine trip, or indirect LOOP, will initiate scram and cause rapid power reduction. The severity of shaft seizure or shaft break, without a LOOP, is evidenced by the fast coastdown of core flow which reduces thermal margin significantly before the L8-initiated scram.

70. STANDARD REVIEW PLAN 15.4.7, REVISION 1 - INADVERTENT LOADING AND OPERATION OF A FUEL ASSEMBLY IN AN IMPROPER POSITION

Difference Plant operating procedures will not contain provisions to search for fuel-loading errors with nuclear instrumentation.

Discussion As addressed in FSAR Section 15.4.7.1, the probability of a fuel bundle being misplaced is extremely small.

The Unit 2 approach is to analyze the worst case (misplaced bundle accident) and show compliance with fuel limits. The analysis and results demonstrating compliance with these limits is presented in FSAR Section 15.4.7.3. (See also GESTAR-II, Section S.2.2.1.8)

71. STANDARD REVIEW PLAN 15.6.4, REVISION 2 - RADIOLOGICAL CONSEQUENCES OF MAIN STEAM LINE FAILURE OUTSIDE CONTAINMENT (BWR)

Difference The iodine concentration in the primary coolant is stated in NUREG-0800, paragraph III.2.b, to correspond to the following two cases:

1. The concentration is the maximum value permitted and corresponds to the conditions of an assumed preaccident spike (meets the 10CFR100 Dose Guidelines).

2. The concentration is the maximum equilibrium value permitted for continued full-power operation (meets 10 percent of the 10CFR100 Dose Guidelines).

The FSAR presents the results of the main steam line failure analysis performed using only Case 1.

Discussion The main steam line failure analysis performed using the more conservative assumption that the iodine concentration in the primary coolant is the maximum value permitted by the BWR standard technical specifications, results in doses that are less than 10 percent of the limits of 10CFR100.

Therefore, FSAR Section 15.6.4 is considered to meet or exceed the requirements of NUREG-0800, Section 15.6.4, without performing the other analysis.

72. STANDARD REVIEW PLAN 15.6.5, REVISION 2 - LOSS-OF-COOLANT ACCIDENTS RESULTING FROM SPECTRUM OF POSTULATED PIPING BREAKS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY

Difference The TMI Task Action Plan requirements for II.E.2.3, II.K.3.25, II.K.3.30, and II.K.3.31 have not been addressed.

Discussion See FSAR Section 1.10 for Tasks II.K.3.25, II.K.3.30, and II.K.3.31. Resolution of Task II.E.2.3 is not addressed in the FSAR but has been generically approved by the NRC.

73. STANDARD REVIEW PLAN 15.8, REVISION 1 - ANTICIPATED TRANSIENTS WITHOUT SCRAM

Difference 1 GDC 10, 15, 26, 27, and 29 are not applied for the ATWS event.

Discussion The postulated ATWS event is so remote that it is outside the range of DBAs to which these GDC apply. The RCPB pressure design has sufficient margin to meet GDC 15.

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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

<u>Difference 2</u> NUREG-0460, Volume 2, Section IV-4, criterion j, is not applicable to the RPT design.

<u>Discussion</u> The NRC reviewed RPT design features during 1978 and 1979 and, after the publication of Volume 2 of NUREG-0460, determined a set of design criteria to determine RPT acceptability. These criteria are essentially the same as criteria a through i of NUREG-0460, Volume 2, Section IV-4. The NRC has deemed the Monticello and Hatch RPT designs as being acceptable since they meet these criteria as noted in SRP 15.8.

74. <u>SRP DEVIATION WRITEUPS, CHAPTER 16 - TECHNICAL SPECIFICATIONS</u>

The information contained in Chapter 16 was finalized in July 1987 when the full-power license was issued. The results of an analysis to determine conformance to the SRP will be provided in a future update.

75. <u>STANDARD REVIEW PLAN 17.1, REVISION 2 - QUALITY ASSURANCE DURING THE DESIGN AND CONSTRUCTION PHASES</u>

This SRP is not applicable to Unit 2. A review of Section 17.1 shows that the program is in conformance to this SRP for the operations phase QA program, as defined in FSAR Appendix B (QA Topical Report).

76. <u>STANDARD REVIEW PLAN 17.2, REVISION 2 - QUALITY ASSURANCE DURING THE OPERATIONS PHASE</u>

QA during the operations phase is discussed in FSAR Appendix B (QA Topical Report). There are no differences noted.

77. <u>STANDARD REVIEW PLAN 18.0, REVISION 0 - HUMAN FACTORS ENGINEERING</u>

SRP acceptance criteria for this section are still being developed. An analysis will be performed when the acceptance criteria are finalized.

TABLE 1.9-1
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STANDARD REVIEW PLAN CONFORMANCE TO ACCEPTANCE CRITERIA

78. STANDARD REVIEW PLAN 13.2.1, REVISION 0 - REACTOR OPERATOR TRAINING

Difference The Licensed Operator Candidate and Licensed Operator Requalification Training Programs comply with 10CFR55 requirements.

Discussion The Licensed Operator Candidate and Requalification Training Programs have been certified as using the Systems Approach to Training, which is an acceptable alternative to the line item requirements of this SRP.

79. STANDARD REVIEW PLAN 11.5, REVISION 3 - PROCESS AND EFFLUENT RADIOLOGICAL MONITORING AND SAMPLING SYSTEMS

Difference Process and effluent radiation monitors are not provided for the ADH system.

Discussion A process radiation monitor was not installed on the secondary side of the ADH system because the possibility of the secondary side of the ADH system becoming contaminated has been analyzed and found not to be a credible event.

80. BTP ICSB 3, REVISION 2 – ISOLATION OF LOW PRESSURE SYSTEMS FROM THE HIGH PRESSURE REACTOR COOLANT SYSTEM

Difference Position indication is not provided for the inboard RCIC check valve.

Discussion Per Technical Specifications Table 3.3.3.1-1, position indication is "not required for isolation valves whose associated penetration flow path is isolated by at least one closed and de-activated automatic valve, closed manual valve, blind valve, or check valve with flow through the valve secured." Therefore, position indication is not required for this valve.

1.10 UNIT 2 RESPONSE TO REGULATORY ISSUES RESULTING FROM THREE MILE ISLAND (TMI) (HISTORICAL)

The information contained in this section provides the Unit 2 project position in response to the requirements for Operating License Applicants identified in NUREG-0737. Table 1.10-1 provides a listing of the tasks from NUREG-0737 for which a project position has been developed.

This section is intended to provide the specific NUREG-0737 positions related to TMI issues, followed by the Unit 2 response as reviewed by the NRC and documented in NUREG-1047 (Unit 2 SER). Accordingly, updated information should be provided in FSAR (or USAR) cross-referenced sections. The original positions described in this section are for historical reference only, and should be preserved.

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NUREG-0737 TMI-2 ITEMS

Section Number	Title
I.A.1.1	Shift Technical Advisor
I.A.1.2	Shift Supervisor Responsibilities
I.A.1.3	Shift Manning
I.A.2.1	Immediate Upgrade of Reactor Operator and Senior Reactor Operator Training and Qualifications
I.A.2.3	Administration of Training Programs
I.A.3.1	Revise Scope and Criteria for Licensing Examinations - Simulator Exams
I.B.1.2	Independent Safety Engineering Group
I.C.1	Short-Term Accident and Procedure Review
I.C.2	Shift and Relief Turnover Procedures
I.C.3	Shift Supervisor Responsibility
I.C.4	Control Room Access
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff
I.C.6	Guidance on Procedures for Verifying Correct Performance of Operating Procedures
I.C.7	NSSS Vendor Review of Procedures
I.C.8	Pilot Monitoring of Selected Emergency Procedures for NTOL Applicants
I.D.1	Control Room Design Reviews
I.D.2	Data Acquisition System - Plant Safety Parameter Display Console
I.G.1	Training During Low-Power Testing
II.B.1	Reactor Coolant System Vents

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NUREG-0737 TMI-2 ITEMS

Section Number	Title
II.B.2	Plant Shielding/Post-accident Access to Vital Areas
II.B.3	Post-accident Sampling
II.B.4	Training for Mitigating Core Damage
II.B.8	Rulemaking Decision on Degraded Core Accidents
II.D.1	Relief and Safety Valve Test Requirements
II.D.3	SRV Position Indication
II.E.4.1	Dedicated Recombiner Penetrations
II.E.4.2	Containment Isolation Dependability
II.F.1	Additional Accident Monitoring Instruments
II.F.2	Inadequate Core Cooling
II.K.1.5	Review of ESF Valves
II.K.1.10	Operability Status
II.K.1.23	Reactor Vessel Level Indication
II.K.3.3	Failure of PORV or Safety Valve to Close
II.K.3.13	Change RCIC Initiation Logic
II.K.3.15	HPCI, RCIC Pipe Break
II.K.3.16	Relief Valve Challenges
II.K.3.17	Report on Outages of Emergency Core Cooling Systems Licensee Report and Proposed Technical Specification Changes
II.K.3.18	ADS Actuation Logic
II.K.3.21	Core Spray and LPCI Auto Restart
II.K.3.22	RCIC Suction Source
II.K.3.24	RCIC and HPCI Support Power

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NUREG-0737 TMI-2 ITEMS

Section Number	Title
II.K.3.25	RCS Pump Seal Design
II.K.3.27	Common Water Level Reference
II.K.3.28	ADS Accumulators
II.K.3.30	Plant-Specific Small Break LOCA Analysis
II.K.3.31	Upgrade of Non-ECCS Items Used in SB LOCA Analysis
II.K.3.44	Transient Analysis
II.K.3.45	Partial Use of ADS
II.K.3.46	Response to ACRS Consultant Concerns
III.A.1.2	Upgrade Emergency Support Facilities
III.A.2	Long-Term Emergency Preparedness
III.D.1.1	Primary Coolant Outside Containment
III.D.3.3	In-Plant Radiation Monitoring
III.D.3.4	Control Room Habitability

NINE MILE POINT UNIT 2 RESPONSE TO TMI REQUIREMENTS

I.A.1.1 SHIFT TECHNICAL ADVISOR

FSAR Cross-Reference

Sections 13.1, 13.2.2

NUREG-0737 Position

Each licensee 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 in the control room. The licensee 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.

The need for the STA position may be eliminated if the qualifications of the Shift Supervisors and Senior Operators have been upgraded and the man-machine interface in the control room has been acceptably upgraded. However, until long-term improvements are attained, the need for a STA program will continue.

The NRC staff will establish the detailed elements of the academic and training requirements of the STA at a later date. The level of upgrading required for licensed operating personnel and the man-machine interface in the control room acceptable for eliminating the need of a STA will also be determined at a later date. Until these requirements for eliminating the STA position have been established, the staff continues to require that a STA be available for duty on each operating shift when a plant is being operated in Modes 1-3 for a BWR. At other times, a STA is not required to be on duty.

Since the accident at TMI, several efforts have been made to establish, for the long term, the minimum level of experience, education, and training for STAs. These efforts include work on the revision to ANS - 3.1, work by the Institute of Nuclear Power Operations (INPO), and internal staff efforts.

INPO has made available a document entitled Nuclear Power Plant Shift Technical Advisor - Recommendations for Position Description, Qualifications, Education and Training. A copy of Revision 0 of this document, dated April 30, 1980, is attached as

a supplement to this task. Sections 5 and 6 of the INPO document describe the education, training, and experience requirements for STAs. The NRC staff finds that the descriptions as set forth in Sections 5 and 6 of Revision 0 to the INPO document are an acceptable approach for the selection and training of personnel to staff the STA positions. The INPO document provides interim guidance for a utility in planning its STA program over the long term.

Applicants for operating licenses shall provide a description of their STA training program and their plans for requalification training on a schedule consistent with the NRC licensing review schedule. This description shall indicate the level of training attained by STAs and demonstrate conformance with the qualification and training requirements.

Applicants for operating licenses shall provide a description of the long-term STA program, including qualification, selection criteria, training plans, and plans, if any, for the eventual phase-out of the STA program on a schedule consistent with the NRC licensing review schedule.

<u>Nine Mile Point Unit 2 Position</u>

The person fulfilling the STA position will meet the qualification requirements of Option 2 (i.e., dedicated STA) of the Policy Statement on Engineering Expertise on Shift described in 50FR43621 and Generic Letter (GL) 86-04. However, if a dedicated STA cannot be provided on a shift, then the Assistant Station Shift Supervisor (ASSS) will function in a dual role (ASSS/STA) and assume the duties of the STA when the Emergency Plan is activated during normal operation, startup, and hot shutdown conditions. Training requirements (Section 13.2) include specific training in the response and analysis of the unit for transients and accidents and in unit design and layout, including capabilities of instrumentation and controls in the control room. The responsibilities of the STA are described in Section 13.1.2.

I.A.1.2 SHIFT SUPERVISOR RESPONSIBILITIES

<u>FSAR Cross-Reference</u>

Sections 13.1, 13.5.1

<u>NUREG-0737 Position</u>[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

[1] Text of NUREG position can be found in NUREG-0578

Supervisor for safe operation of the plant under all conditions on his shift, and that clearly establishes his command duties.

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:

1. 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 idea 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.

2. 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.

3. 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 authorities shall be clearly specified.

Training programs for Shift Supervisors shall emphasize and reinforce the responsibility for safe operation and the management function of the Shift Supervisor is to provide for assuring safety.

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.

The following table provides clarification to the above position

SHIFT SUPERVISOR RESPONSIBILITY (2.2.1.a)

NUREG-0578 Position (Position No.)	Clarification
Highest level of corporate management (1)	Chief Nuclear Officer
Periodically reissue (1)	Annual reinforcement of company policy
Management direction (1)	Formal documentation of shift personnel, all plant management, copy to IE region
Properly defined (2.0)	Defined in writing in a plant procedure
Until properly relieved (2.B)	Formal transfer of authority valid Senior Reactor Operator (SRO) license recorded in plant log
Temporarily absent (2.C)	Any absence
Control room defined (2.C)	Includes Shift Supervisor office adjacent to control room
Designated (2.C)	In administrative procedures
Clearly specified (2.C)	Defined in administrative procedures
SRO training (3)	Specified in ANS-3.1 (Draft) Section 5.2.1.8)
Administrative duties reviewed (4)	Not affecting plant safety
Administrative duties reviewed (4)	On same interval as reinforcement; i.e., annual by Vice President Nuclear Generation

Nine Mile Point Unit 2 Position

Prior to fuel loading and annually thereafter, the Chief Nuclear Officer shall issue a management directive that emphasizes the primary management responsibility of the Station Shift Supervisor

* This requirement shall be met before fuel loading. See NUREG-0578, Section 2.2.1.a, Item 4 and NRC letters of September 27, and November 9, 1979.

(SSS) for safe operation of the plant under all conditions on his shift and clearly establishes his command duties.

Plant procedures are written to ensure that the duties, responsibilities, and authority of the SSS and other licensed Control Room Operators are properly defined to implement the chain of command.

Administrative duties of the SSS have been reviewed, and many administrative functions have been assigned to other personnel not involved with actual operation of the reactor. Administrative duties of the SSS are reviewed annually by the Vice President Nuclear Generation to ensure that such functions do not detract from safe plant operation.

The responsibilities of the SSS are described in Section 13.1.2.

Training programs for the Senior Reactor Operators (SROs) reinforce the responsibility for safe operation and the management function of the Control Room Supervisor to ensure safety.

I.A.1.3 SHIFT MANNING

FSAR Cross-Reference

Sections 13.1, 13.5.1, Technical Specifications Section 6.2

NUREG-0737 Position

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 plant personnel qualified to man 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., SROs, Reactor Operators [RO], Health Physicists, Auxiliary Operators, I&C 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 (see WNP-2 position).

The staff recognizes 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-hr working day, the effects of shift rotation, and other factors. The NRC has 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 hr straight (not including shift turnover time).

2. There should be a break of at least 12 hr (which can include shift turnover time) between all work periods.

3. An individual should not work more than 72 hr 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 his deputy, or higher levels of management in accordance with published procedures and with appropriate documentation of the cause.

If a RO or SRO has been working more than 12 hr 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-hr break preceding such an assignment.

The NRC encourages the development of a staffing policy that would permit the Licensed ROs and SROs to be periodically assigned to other duties away from the control board during their normal tours of duty.

If a RO is required to work in excess of 8 continuous hours, he shall be periodically relieved of primary duties at the control board, so that periods of duty at the board do not exceed about 4 hr at a time. The guidelines on overtime do not apply to the STA provided he or she is provided sleeping accommodations and a 10-min 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.

See Task III.A.1.2 for minimum staffing and augmentation capabilities for emergencies.

Nine Mile Point Unit 2 Position

Shift manning for Unit 2 is consistent with the requirements of the Technical Specifications and Site Administrative Procedures, and meets all minimum requirements for this task.

I.A.2.1 IMMEDIATE UPGRADE OF REACTOR OPERATOR AND SENIOR REACTOR OPERATOR TRAINING AND QUALIFICATIONS

FSAR Cross-Reference

Section 13.2

NUREG-0737 Position

Effective December 1, 1980, an applicant for a SRO license will be required to have been a Licensed Operator for 1 yr. 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 Operators. This was clearly a poor practice and the letter of March 28, 1980, requires RO experience for SRO applicants.

However, the NRC does not wish to discourage Staff Engineers from becoming licensed SROs. This 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, the NRC should provide an alternate path to holding an Operator's license for one year.

The track followed by a high school graduate (a nondegreed individual) to become a SRO would be 4 yr as a Control Room Operator, at least 1 of which would be as a Licensed Operator, and participation in a 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 yr of responsible nuclear power plant experience as a Staff Engineer, participation in a SRO training program equivalent to a cold applicant training program, and 3 months on shift as an extra person in training for a SRO position.

Holding these positions assures that individuals who will direct the licensed 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-yr 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 requirement, provided they meet the requirements set forth in Sections A.1.a and A.2 in enclosure 1 in the letter from H. R. Denton and 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.

The NRC has not imposed the 1-yr 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.

Nine Mile Point Unit 2 Position

The upgrading of Operator Training and Senior Operator Training for Unit 2 is being performed as described in Section 13.2 of the FSAR. This is also in accordance with the Site Administrative Procedures.

I.A.2.3 ADMINISTRATION OF TRAINING PROGRAMS

FSAR Cross-Reference

Section 13.2

NUREG-0737 Position

Pending accreditation of training institutions, licensees and applicants for operating licenses will assure that training center and facility instructors who teach systems, integrated responses, transient, and simulator courses demonstrate SRO qualifications and are enrolled in appropriate requalification programs.

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 a Senior Operator examination.

The purpose of the examination is to provide the NRC with reasonable assurance during the interim period that instructors are technically competent. The requirement is directed to permanent members of the training staff who teach the subjects enumerated 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 a Senior Operator examination. Nor do we intend to require a system expert, such as the Supervisor Instrument and Control Maintenance teaching the rod control drive system, to sit for a Senior Operator examination. The use of guest lecturers should be limited.

<u>Nine Mile Point Unit 2 Position</u>

Instructors who teach systems, integrated responses, transient, and simulator courses to Operators hold SRO licenses or certifications and participate in Operator requalification programs, as outlined in Nuclear Training Procedures. Vendor instructors hold SRO certifications from their respective companies and participate in the Operator requalification program.

The qualification of the training instructors meets the requirements of this task, as described in Section 13.2 of the FSAR.

I.A.3.1 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS - SIMULATOR EXAMS

<u>FSAR Cross-Reference</u>

Section 13.2

<u>NUREG-0737 Position</u>

Simulator examinations will be included as part of the licensing examinations. The administration of simulator examinations will be deferred for applicants whose facilities do not have simulators onsite as of October 1, 1980. These deferred simulator examinations will be initiated by October 1, 1981.

The clarification provides additional preparation time for utility companies and the 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 on 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 hr. 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 not later than 2 weeks after the balance of the examination.

Nine Mile Point Unit 2 Position

All new licensing examinations will utilize a control room simulator. The simulator for Unit 2 has been ordered, and it is expected to be operational in January 1985.

I.B.1.2 INDEPENDENT SAFETY ENGINEERING GROUP

FSAR Cross-Reference

Section 13.4 and the Technical Specifications

NUREG-0737 Position

Each applicant for an operating license shall establish an onsite Independent Safety Engineering Group (ISEG) to perform independent reviews of plant operations.

The principle function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities, including maintenance, modifications, operational problems, and operational analysis, and to aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. ISEG will then be in a position to advise utility management on the overall quality and safety of operations. ISEG need not perform detailed

audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

The new ISEG shall not replace the Plant Operations Review Committee (PORC) and the utility's independent review and audit group as specified by current staff guidelines (Standard Review Plan [SRP], RG 1.33, Standard Technical Specifications). Rather, it is an additional independent group of a minimum of five dedicated, full-time Engineers, located onsite but reporting offsite to a corporate official who holds a high-level, technically-oriented position that is not in the management chain for power production. The ISEG will increase the available technical expertise located onsite and will provide continuing, systematic, and independent assessment of plant activities. Integrating the STAs into the ISEG in some way would be desirable in that it could enhance the group's contact with the knowledge of day-to-day plant operations to provide additional expertise. However, the STA on shift is necessarily a member of the operating staff and cannot be independent of it.

It is expected that the ISEG may interface with the Quality Assurance (QA) organization, but preferably should not be an integral part of the QA organization.

The functions of the ISEG require daily contact with the operating personnel and continued access to plant facilities and records. The ISEG review functions can therefore best be carried out by a group physically located onsite. However, for utilities with multiple sites, it may be possible to perform portions of the independent safety assessment function in a centralized location for all the utility's plants. In such cases, an onsite group still is required, but it may be slightly smaller than would be the case if it were performing the entire independent safety assessment function. Such cases will be reviewed on a case-by-case basis.

At this time, the requirement for establishing an ISEG is being applied only to applicants for operating licenses in accordance with Task I.B.1.2. The staff intends to review this activity in about a year to determine its effectiveness and to see whether changes are required. Applicability to operating plants will be considered in implementing long-term improvements in organization and management for operating plants (Task I.B.1.1).

Nine Mile Point Unit 2 Position

An onsite ISEG will be established to perform independent reviews of plant operation. The principal function of the ISEG is to examine plant operating characteristics and the various NRC and industry licensing and service advisories, and to recommend areas for improving plant operations or safety. The ISEG also performs investigative functions as requested and performs independent review of plant activities, including maintenance, modifications,

operational concerns and analysis, and makes recommendations to the Vice President Nuclear Safety Assessment & Support.

The Unit 1 and 2 Plant Managers are members of the Safety Review and Audit Board (SRAB). The Plant Managers in turn chair the Station Operations Review Committee (SORC). This ensures that the flow of internal and external operating experience is communicated to SRAB and SORC while maintaining the independent status of ISEG. ISEG chairs the SRAB subcommittee which evaluates the effectiveness of dispositioned operating experiences identified by the Deviation/Event Report (DER) process.

The ISEG will observe plant operations and maintenance activities to determine that these activities are being performed properly and provide written recommendations (when useful improvements can be achieved). The ISEG does not perform detailed (QA-type) audits and is not responsible for signoff functions associated with daily operational activities. The ISEG is independent of the SORC and SRAB, but may make recommendations to these groups.

The ISEG shall be composed of at least five dedicated, full-time Engineers located onsite, assigned to Unit 2, who report to the Vice President Nuclear Safety Assessment & Support. Each shall have a bachelor's degree in engineering or related science and at least 2 yr professional level experience in his field, at least 1 yr of which experience shall be in the nuclear field.

I.C.1 SHORT-TERM ACCIDENT AND PROCEDURE REVIEW

FSAR Cross-Reference

Sections 13.5.2, 14.2

NUREG-0737 Position

In letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation 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 (EPGs), upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct Operator retraining (see also Task I.A.2.1). 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 EPGs were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of review of these matters on Babcock and Wilcox (B&W)-designed plants, the staff will follow up on the bulletin

and orders matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C.

Changes to Previous Requirements and Guidance

1. Modification to Clarification:

   a. Addresses Owners' Group and vendor submittals.

   b. References to Tasks I.C.8 and I.C.9.

   c. Scope of procedures review is explained.

   d. Establishes configuration control of guidelines for emergency procedures.

2. Modification to Implementation: Deleted reference to NUREG-0578, Recommendation 2.1.9 for Task I.C.1(a)2, Inadequate Core Cooling.

The letters of September 13 and 27, October 10 and 30, and November 9, 1979, required that procedures and Operator training be developed for transients and accidents. The initiating events to be considered were to include the events presented in the FSAR: loss of instrumentation buses, and natural phenomena such as earthquakes, floods, and tornadoes. The purpose of this paper is to clarify the requirements and add additional requirements for the reanalysis of transients and accidents and inadequate core cooling.

Based on staff reviews to date, there appear to be some recurring deficiencies in the guidelines being developed. Specifically, the staff has found a lack of justification for the approach used (i.e., symptom-, event-, or function-oriented) in developing diagnostic guidance for the Operator and in procedural development. It has also been found that although the guidelines take implicit credit for operation of many systems or components, they do not address the availability of these systems under expected plant conditions, nor do they address corrective or alternative actions that should be performed to mitigate the event should these systems or components fail.

The analyses conducted to date for guideline and procedure development contain insufficient information to assess the extent to which multiple failures are considered. NUREG-0578 concludes that the single-failure criterion was not considered appropriate for guideline development and calls for the consideration of multiple failures and Operator errors. Therefore, the analyses that support guideline and procedure development should consider the occurrences of multiple and consequential failures. In general, the sequence of events for the transients and accidents and inadequate core cooling analyzed should postulate multiple failures such that, if the failures were unmitigated, conditions of inadequate core cooling would result.

Examples of multiple failure events include:

1. Multiple tube ruptures in a single steam generator and tube rupture in more than one steam generator.

2. Failure of main and auxiliary feedwater.

3. Failure of high-pressure reactor coolant makeup system.

4. ATWS event following a LOOP, stuck-open relief valve or SRV, or loss of main feedwater.

5. Operator errors of omission or commission.

The analyses should be carried out far enough into the event to assure that all relevant thermal/hydraulic/neutronic phenomena are identified (e.g., upper head voiding due to rapid cooldown, steam generator stratification). Failures and Operator errors during the long-term cooldown period should also be addressed.

The analyses should support development of guidelines that define a logical transition from the emergency procedures into the inadequate core cooling procedure, including the use of instrumentation to identify inadequate core cooling conditions. Rationale for this transition should be discussed. Additional information that should be submitted includes:

1. A detailed description of the methodology used to develop the guidelines.

2. Associated control function diagrams, sequence-of-event diagrams, or others, if used.

3. The bases for multiple and consequential failure considerations.

4. Supporting analysis, including a description of any computer codes used.

5. A description of the applicability of any generic results to plant-specific applications.

Owners' Group or vendor submittals may be referenced as appropriate to support this reanalysis. If Owners' Group or vendor submittals have already been forwarded to the staff for review, a brief description of the submittals and justification of their adequacy to support guideline development is all that is required.

Pending staff approval of the revised analysis and guidelines, the staff will continue the pilot monitoring of emergency procedures described in Task I.C.8 (NUREG-0660). Since the analysis and guidelines submitted by the GE Owners' Group that

comply with the requirements stated above have been reviewed and approved for trial implementation on six plants with applications for operating licenses pending, the interim program for BWRs will consist of trial implementation on these six plants.

Following approval of analysis and guidelines and the pilot monitoring of emergency procedures, the staff will advise all licensees of the adequacy of the guidelines for application to their plants. Consideration will be given to human factors engineering and system operational characteristics, such as information transfer under stress, compatibility with Operator training and control room design, the time required for component and system response, clarity of procedural actions, and control room-personnel interactions. When this determination has been made by the staff, a long-term plan for emergency procedure review, as described in Task I.C.9, will be made available. At that time, the reviews currently being conducted on NTOLs under Task I.C.8 will be discontinued, and the review required for applicants for operating licenses will be as described in the long-term plan.

Depending on the information submitted to support development of emergency procedures for each reactor type or vendor, this transition may take place at different times. For example, if the GE guidelines are shown to be effective on the six plants chosen for pilot monitoring, the long-term plan for BWRs may be complete in early 1981. Operating plants and applicants will then have the option of implementing the long-term plan in a manner consistent with their operating schedule, provided they meet the final date required for implementation. This may require a plant that was reviewed for an operating license under Task I.C.8 to revise its emergency procedures again prior to the final implementation date for Task I.C.9.

The extent to which the long-term program will include review and approval of plant-specific procedures for operating plants has not been established. Our objective, however, is to minimize the amount of plant-specific procedure review and approval required. The staff believes this objective can be acceptably accomplished by concentrating the staff review and approval on generic guidelines. A key element in meeting this objective is the use of staff-approved generic guidelines and guideline revisions by licensees to develop procedures. For this approach to be effective, it is imperative that, once the staff has issued approval of a guideline, subsequent revisions of the guideline should not be implemented by licensees until reviewed and approved by the staff. Any changes in plant-specific procedures based on unapproved guidelines could constitute an unreviewed safety issue under 10CFR50.59. Deviations from this approach on a plant-specific basis would be acceptable provided the basis is submitted by the licensee for staff review and approval. In this case, deviations from generic guidelines should not be implemented until staff approval is formally received in writing. Interim implementation of analysis and procedures for small break

LOCA and inadequate core cooling should remain on the schedule contained in NUREG-0578, Recommendation 2.1.9.

Nine Mile Point Unit 2 Position

The Unit 2 project has monitored the development of the BWR Owners' Group (BWROG) emergency procedures.

Unit 2 emergency operating procedures (EOP) are developed using the BWROG EPG (Revision 4). Deviations (additions, deletions or changes) from the generic document are documented as an appendix to the plant-specific technical guideline (PSTG). Based upon discussions between the BWROG and the NRC, NRC approval of deviations from the NRC-approved EPGs (Revision 4) is not required unless deviations are major strategy changes (BWROG letter OG90-791-62). All deviations are reviewed for technical content and approved by the Unit 2 Operations and Engineering Departments.

I.C.2 SHIFT AND RELIEF TURNOVER PROCEDURES

FSAR Cross-Reference

Section 13.5.1

NUREG-0737 Position[1]

The licensees 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:

(1)Text of NUREG position can be found in NUREG-0578.

   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 in the checklist).

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[1]Text of NUREG position can be found in NUREG-0578.

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 ongoing 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).

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 shift relief turnover procedures will include:

1. A checklist for incoming and outgoing Control Room Operators and incoming 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 in the checklist.)

   c. Identification of systems and components that are in an off-normal or out-of-service mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the off-normal or out-of-service mode shall be compared with the Technical Specifications action statement, if any. (This shall be recorded as a separate entry on the checklist.)

2. Checklists or logs shall be provided for completion by outgoing and incoming Operators. 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 transient and accidents, initiate operational transients and accidents, or initiate an operational transient. (What to check and criteria for acceptable status shall be included on the checklist.)

3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure.

I.C.3 SHIFT SUPERVISOR RESPONSIBILITY

FSAR Cross-Reference

Sections 13.1, 13.5.1

NUREG-0737 Position[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.

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:

1. 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 idea 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.

2. The Shift Supervisor, until properly relieved of duty, 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.

[1] Text of NUREG position can be found in NUREG-0578

3. 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 the authority shall be clearly specified.

Training programs for Shift Supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the Shift Supervisor is to provide for assuring safety.

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.

The following table clarifies this position:

SHIFT SUPERVISOR RESPONSIBILITY (2.2.1.a)

NUREG-0578 Position (Position No.)	Clarification
Highest level of corporate management (1)	Chief Nuclear Officer
Periodically reissue (1)	Annual reinforcement of company policy
Management direction (1)	Formal documentation of shift personnel, all plant management, copy to IE region
Properly defined (2.0)	Defined in writing in a plant procedure
Until properly relieved (2.8)	Formal transfer of authority, valid SRO license, recorded in plant log
Temporarily absent (2.C)	Any absence
Control room defined (2.C)	Includes Shift Supervisor office adjacent to the control room
Designated (2.C)	In administrative procedures
Clearly specified	Defined in administrative procedures
SRO training	Specified in ANS-3.1 (Draft) Section 5.2.1.8
Administrative duties (4)	Not affecting plant safety
Administrative duties reviewed (4)	On same interval as reinforcement; i.e., annual by Chief Nuclear Officer

Nine Mile Point Unit 2 Position

The response to this task is contained in I.A.1.2.

Refer to Task I.A.1.2 position statement for response to I.C.3.

I.C.4 CONTROL ROOM ACCESS

FSAR Cross-Reference

Section 13.5

NUREG-0737 Position[1]

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 the operation, and to 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, and

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 SRO 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 of the control room.

Nine Mile Point Unit 2 Position

Unit 2 will utilize procedures that limit control room access to those individuals responsible for direct operation of the plant, technical advisors requested or required to support operation, and NRC personnel as described below:

1. Procedures establish the authority and responsibility of the person in charge of the control room to limit access.

2. Procedures 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 includes those holding a SRO license. The Emergency Plan clearly defines 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.

I.C.5 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF

FSAR Cross-Reference

Section 13.5.1

NUREG-0737 Position

In accordance with Task I.C.5, Procedures for Feedback of Operating Experience to Plant Staff (NUREG-0660), each applicant for an operating license shall prepare procedures to assure that operating information pertinent to plant safety originating both within and outside the utility organization is continually supplied to Operators and other personnel and is incorporated into training and retraining programs. These procedures shall:

1. Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to Operators and other personnel, and the incorporation of such information into training and retraining programs;

2. Identify the administrative and technical review steps necessary in translating recommendations by the Operating Experience Assessment (OEA) group into plant actions (e.g., changes to procedures, operating orders);

3. Identify the recipients of various categories of information from operating experience (i.e., supervisory personnel, STAs, Operators, Maintenance personnel, Health Physics Technicians) or otherwise provide means through which such information can be readily related to the job functions of the recipients;

4. Provide means to assure that affected personnel become aware of and understand information of sufficient importance that it should not wait for emphasis through routine training and retraining programs;

5. Assure that plant personnel do not routinely receive extraneous and unimportant information on operating experience in such volume that it would obscure priority information or otherwise detract from overall job performance and proficiency;

6. Provide suitable checks to assure that conflicting or contradictory information is not conveyed to Operators and other personnel until resolution is reached; and,

7. Provide periodic internal audit to assure that the feedback program functions effectively at all levels.

Each utility shall carry out an OEA function that will involve utility personnel having collective competence in all areas important to plant safety. In connection with this assessment function, it is important that procedures exist to assure that important information on operating experience originating both within and outside the organization is continually provided to Operators and other personnel, and that it is incorporated into plant operating procedures and training and retraining programs.

Those involved in the assessment of operating experience will review information from a variety of sources. These include operating information from the licensee's own plant(s), publications such as IE Bulletins, Circulars, and Notices, and pertinent NRC or industrial assessments of operating experience. In some cases, information may be of sufficient importance that it must be dealt with promptly (through instructions, changes to operating and emergency procedures, issuance of special precautions, etc.), and must be handled in such a manner to assure that operations management personnel would be directly involved in the process. In many other cases, however, important information will become available which should be brought to the attention of Operators and other personnel for their general information to assure continued safe plant operation.

Since the total volume of information handled by the assessment group may be large, it is important that assurance be provided that high priority matters are dealt with promptly and that discrimination is used in the feedback of other information so that personnel are not deluged with unimportant and extraneous information to the detriment of their overall proficiency. It is important, also, that technical reviews be conducted to preclude premature dissemination of conflicting or contradictory information.

Nine Mile Point Unit 2 Position

Unit 2 will utilize administrative and training procedures to implement operating experience feedback to the plant staff. These procedures will:

1. Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to Operators and other personnel, and the incorporation of such information in training and requalification training programs (Section 13.2.4.1.1, Item 9).

2. Identify the administrative and technical review steps necessary to translate recommendations that are the result of an OEA function, which is performed by the processing of DERs into plant actions (e.g., changes to procedures and operating orders). Sections 13.4 and 1.10 provide information concerning the OEA function.

3. Identify the recipients of various categories of operating experience information (i.e., shift or supervisor, personnel) or otherwise provide means through which such information can be readily related to the job functions of the recipients (Section 13.2.4.1.3).

4. Provide means to ensure that affected personnel become aware of and understand information of sufficient importance so that this information should not wait for emphasis through routine training and retraining, standing orders or night orders. (For example, required reading assignments are made on an ongoing basis to address this concern.)

5. Ensure that plant personnel do not routinely receive extraneous information on operating experience in such volume that it could obscure priority information.

6. Provide suitable checks to ensure that correct information is conveyed to Operators and other personnel.

7. Provide periodic audits to ensure that the feedback program functions effectively (e.g., training audits).

OEA is performed on an ongoing basis by the processing of DERs by the responsible organization which is considered most cognizant over the subject matter of the DER. The individuals involved review information from a variety of sources such as IE Bulletins, IE Information Notices, INPO reports, Licensee Event Reports (LERs), and vendor information letters such as Service Information Letters (SILs).

The feedback system provides for early notification of significant information to operating personnel and management. The DER evaluation process provides assurance that the information is correct and that unimportant and extraneous information does not impact overall proficiency.

I.C.6 GUIDANCE ON PROCEDURES FOR VERIFYING CORRECT PERFORMANCE OF OPERATING PROCEDURES

<u>FSAR Cross-Reference</u>

Section 13.5

NUREG-0737 Position

It is required 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, or both.

Implementation of automatic status monitoring, if required, will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with Task I.D.3.

Task I.C.6 of the NRC Task Action Plan (NUREG-0660) and Recommendation 5 of NUREG-0585 propose requiring 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. An acceptable program for verification of operating activities is described below.

The American Nuclear Society (ANS) has prepared a draft revision to ANSI Standard N18.7-1972 (ANS-3.2), Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants. A second proposed revision to RG 1.33, Quality Assurance Program Requirements (Operation), which is to be issued for public comment in the near future, will endorse the latest draft revision to ANS-3.2 subject to the following supplemental provisions:

1. Applicability of the guidance of Section 5.2.6 should be extended to cover surveillance testing in addition to maintenance.
2. In lieu of any designated SRO, the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an on-shift SRO, provided provisions are made to ensure that the Shift Supervisor is kept fully informed of system status.

3. Except in cases of significant radiation exposure, a second qualified person should verify correct implementation of equipment control measures such as tagging of equipment.

4. Equipment control procedures should include assurance that Control Room Operators are informed of changes in equipment status and the effects of such changes.

5. For the return-to-service of equipment important to safety, a second qualified Operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and can prove that all equipment, valves, and switches involved in the activity are correctly aligned.

NOTE: A licensed Operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person. The staff is investigating the level of qualification necessary for other Operators to perform these functions.

For plants that have or will have automatic system status monitoring as discussed in Task I.D.3, NUREG-0660, the extent of human verification of operations and maintenance activities will be reduced. However, the need for such verification will not be eliminated in all instances.

Nine Mile Point Unit 2 Position

Unit 2 will utilize procedures and equipment to ensure an effective system of verifying correct performance of operating activities. As part of the overall program, the Unit 2 design incorporates an automatic status system and bypass inoperability system. Unit 2 is committed to RG 1.33 (Section 1.8) and the following:

1. ANSI N18.7-1976, Section 5.26, is applied to both maintenance and surveillance testing.

2. The authority to release systems and equipment for maintenance or surveillance testing or return to service may be delegated to either the SSS (SRO) or Chief Shift Operator (SRO), provided the SSS is kept informed.

3. Except in cases of significant radiation exposure, a second qualified person shall verify correct implementation of equipment control measures such as tagging of equipment.

4. Equipment control procedures shall include assurance that Control Room Operators are informed of changes in equipment status and the effects of such changes.

5. For the return to service of safety-related equipment, a second qualified Operator shall verify proper systems alignment, unless functional testing can be performed without compromising plant safety and can prove that

equipment valves and switches involved in the activity are correctly aligned.

Equipment control procedures described in Section 13.5.1.3.3 provide assurance that this guidance is implemented.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

FSAR Cross-Reference

Sections 13.5.2, 14.2

NUREG-0737 Position[1]

Obtain NSSS vendor review of low power testing procedures to further verify their adequacy. This requirement must be met before fuel loading (NUREG-0694).

Nine Mile Point Unit 2 Position

On April 14, 1983, Unit 2 committed in a letter from C. V. Mangan to D. G. Eisenhut to provide a procedures generation package based upon NRC-approved BWROG EPGs. Additionally, the NSSS vendor, GE, and the architect-engineer, SWEC, will be reviewing procedures by their participation on the Joint Test Group. This commitment fulfills this requirement.

I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NTOL APPLICANTS

FSAR Cross-Reference

Section 13.5.2

NUREG-0737 Position[1]

Correct emergency procedures, as necessary, based on the NRC audit of selected plant EOPs (e.g., small break LOCA, loss of feedwater, restart of ESFs following a loss of ac power, steam line break, or steam generator tube rupture). This action will be completed prior to issuance of a full power license (NUREG-0694).

Nine Mile Point Unit 2 Position

On April 14, 1983, in a letter from C. V. Mangan to D. G. Eisenhut, Unit 2 committed to provide a procedure generation package based upon NRC-approved BWROG EPGs. This commitment fulfills this requirement.

[1]Text of NUREG position can be found in NUREG-0694.

I.D.1 CONTROL ROOM DESIGN REVIEWS

FSAR Cross-Reference

Section 18.1

NUREG-0737 Position

All licensees and applicants for operating licenses will be required to conduct a detailed control room design review (DCRDR) to identify and correct design deficiencies. This DCRDR is expected to take about a year. Therefore, the Office of Nuclear Reactor Regulation requires that applicants for operating licenses who are unable to complete this review prior to issuance of a license make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by the NRC 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 (NUREG-0737).

The Office of Nuclear Reactor Regulation is presently developing human engineering guidelines to assist each licensee and applicant in performing a detailed control room review. A draft of the guidelines has been published for public comment as NUREG/CR-1580, Human Engineering Guide to Control Room Evaluation. The Office of Nuclear Reactor Regulation issued the final version of the guidelines as NUREG-0700 in September 1981, after receiving, reviewing, and incorporating substantive public comments from operating reactor licensees, applicants for operating licenses, human factors engineering experts, and other interested parties. The Office of Nuclear Reactor Regulation will evaluate the applicants' preliminary assessments including the performance by the Office of Nuclear Reactor Regulation of onsite review/audit. The Office of Nuclear Reactor Regulation onsite review/audit will be on a schedule consistent with licensing needs and will emphasize the following aspects of the control room:

1. Adequacy of information presented to the Operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions.
2. Groupings of displays and the layout of panels.
3. Improvements in the safety monitoring and human factors enhancement of controls and control displays.
4. Communications from the control room to points outside the control room, such as the onsite Technical Support Center (TSC), remote shutdown panel (RSP), offsite telephone lines, and to other areas within the plant for normal and emergency operation.

5. Use of direct rather than derived signals for the presentation of process and safety information to the Operator.

6. Operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems.

7. Adequacy of operating procedures and Operator training with respect to limitations of instrumentation displays in the control room.

8. Categorization of alarms, with unique definition of safety alarms.

9. Physical location of the Shift Supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, the Office of Nuclear Reactor Regulation 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.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 project will utilize the guidance provided by the NRC Committee to Review Generic Requirements (CRGR) as stated in SECY 82-111.

Unit 2 has provided a commitment to follow the guidance provided by Supplement 1 to NUREG-0737 in Unit 2 Letter No. 6438, dated April 14, 1983, to D. G. Eisenhut, Division of Licensing of the NRC.

Unit 2 has performed a preliminary control room design review based on the BWROG program. The survey was structured with a team consisting of representatives from Unit 2, other utilities, the NSSS supplier, and a human factors consultant. This group included licensed SROs.

The review included panel layout and design, instrumentation, hardware, and annunciators. The preliminary review was set up to identify areas where potential changes could be made in the power generating control center (PGCC) shop prior to shipment to the site in early 1983. The final control room design review will be conducted during 1983 or 1984 based on the guidance of NUREG-0700. The following paragraphs provide a description of this review.

<u>Purpose and Scope</u> The purpose of the control room design review described is to: 1) review and evaluate the control room workspace, instrumentation, controls, and other equipment from a human factors engineering point of view that takes into account both system demands and Operator capabilities; and 2) to

identify, assess, and implement control room design modifications that improve control room man-machine interfaces. The scope of the Unit 2 control room design review described covers the human factors engineering aspects of the completed control room.

Objectives The control room design review will accomplish the following objectives:

1. To determine whether the control room provides the system status information, control capabilities, feedback, and analytic aids necessary for Control Room Operators to accomplish their functions effectively.

2. To identify characteristics of existing control room instrumentation, controls, other equipment, and physical arrangements that may detract from Operator performance.

3. To analyze and evaluate the problems that could arise from discrepancies of Items 1 and 2, and to analyze means of correcting those discrepancies.

4. To define and put into effect a plan of action that applies human factors principles to improve control room design and enhance Operator effectiveness. Particular emphasis will be placed on improvements affecting control room design and Operator performance under abnormal or emergency conditions.

5. To integrate the control room design review with other areas of human factors inquiry identified as a result of TMI-related requirements.

Relationship to Other Human Factors Programs The control room design review will be integrated with other TMI issues that are also concerned with or may affect control room human factors. Most of these programs are described in NRC Task Action Plan NUREG-0660 and NUREG-0737. Aspects of the TMI-Related Requirements for New Operating Licenses (NUREG-0694) and Functional Criteria for Emergency Response Facilities (NUREG-0696) are also pertinent.

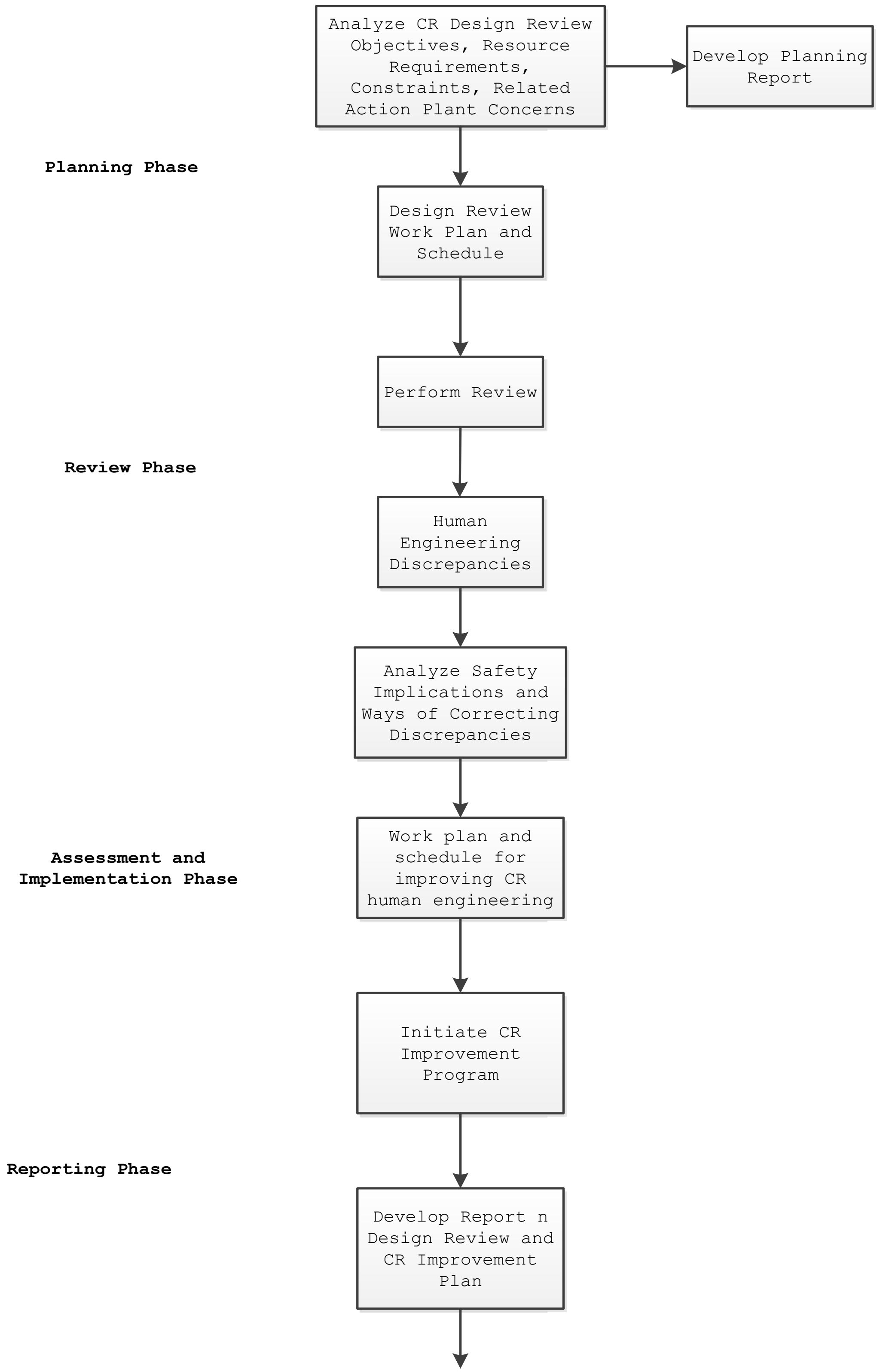
Control Room Design Review Process The control room design review process addresses four major phases of activity, as illustrated in Exhibit 1A: planning, review, assessment and implementation, and reporting. Methods and procedures, as suggested by NUREG-0700, are used as guidance for accomplishing that portion of the review. Alternatives to that guidance may be used and will be clearly documented.

Planning A formal planning phase will be performed which will take into account the data and information needs of related control room human factors efforts, so that a data base can be developed to meet common needs. Other features of the planning

phase will involve management in the overall control room design review process, to ensure that all objectives and tasks are fully understood, to develop a well-defined work plan and schedule that takes operational constraints into account, and to ensure that the resources needed to complete the review on schedule will be available. A preliminary report summarizing the formal planning phase will be prepared.

EXHIBIT I.D.1-1

OVERVIEW OF CONTROL ROOM (CR) DESIGN REVIEW PHASES AND PRODUCTS



Review The review phase is directed toward identifying and documenting human engineering discrepancies. A system point of view is used so that the assessment of control room characteristics will be tied to their functional applications and operational interrelationships. The term system, as used here, includes personnel as well as hardware; the design review addresses the man-machine system configuration. The processes are defined for the review phase:

1. Review and analysis of system functions and Control Room Operator tasks, to establish the instrumentation and equipment requirements and the performance criteria for the tasks Operators are expected to accomplish.

2. Inventory of the control room, to identify and describe the performance features of the existing instrumentation and equipment.

3. Survey of the control room, in which the instrumentation, controls, other equipment, ambient conditions, and other features are checked against human engineering guidelines.

4. Verification of task performance capabilities, in which the instrument and equipment requirements derived from task analysis are compared to the items presently in the control room inventory.

5. Validation of the control room functions, in which the relationships and dependencies in operating crew activities and between the Operators and plant processes are examined in the context of operational sequences.

Assessment and Implementation The processes of the review phase will identify and describe control room design features that may adversely affect Operator performance. In the assessment and implementation phase, human engineering discrepancies will be assessed and the process of correcting them (implementation) initiated. Assessment involves determining the safety significance of discrepancies and analyzing them to select design improvements. Discrepancies that have no particular safety significance will also be assessed and analyzed for correction, but on a lower priority basis. Cost-benefit or cost-effectiveness analyses will be a part of the assessment process. Assessment also involves establishing priorities and schedules for corrective action, determining the extent of corrections, and addressing any recommendations or decisions not to implement modifications.

The assessment process will ensure that the control room design review has been appropriately integrated with those other control room-related projects that are concerned with or may affect human factors. Corrective actions identified in this phase will be

reviewed to ensure their consistency with the goals of related projects.

Design improvements that can be executed without interfering with normal control room operation (e.g., changes in surface features such as labeling and location aids) will be implemented in a timely fashion consistent with the project schedule. Other improvements that involve changes to control room equipment or design or that require Operator retraining will be scheduled for introduction on a schedule consistent with their significance to plant safety and with operational considerations.

Reporting Reports will be prepared to summarize the review process:

1. Program Planning A preliminary report will be prepared at the conclusion of the planning phase. This report will summarize the planned review process, including methods, staff qualifications, scope of the review effort, and plans for integrating the review.

2. Design Review A final report will be prepared that summarizes the overall review process. Three principal topics will be addressed:

   a. Methodology This section will reference the program planning report and update that material with any changes made during the course of the review.

   b. Review Findings This section will summarize the documentation of the status of the control room with respect to the guidelines for system function review and task analysis, and human engineering guidelines. The section will identify equipment, controls, or displays that may be in the control room and missing features that are needed for improved performance of control room evaluation. Problems related to operational dynamics in crew performance and procedures will be discussed.

      Discrepancies with safety consequences will be described, as well as the design and design review processes (including any reallocation of functions) selected for their resolution. Decisions not to take corrective action will be addressed.

   c. Implementation This section will provide a summary of control room design improvements already completed and will identify improvements to be completed at a later date. Improvements scheduled for long-term implementation will be

described. A suggested schedule will be developed based upon priority and safety significance.

I.D.2 DATA ACQUISITION SYSTEM-PLANT SAFETY PARAMETER DISPLAY CONSOLE

FSAR Cross-Reference

Sections 7.5, 7.6, 18.2

NUREG-0737 Position

Plant Safety Parameter Display Console (I.D.2) In accordance with Task I.D.2, Plant Safety Parameter Display Console (NUREG-0660), each applicant and licensee shall install a safety parameter display system (SPDS) that will display to operating personnel a minimum set of parameters that 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 (NUREG-0737).

The requirements for the SPDS have been developed in NUREG-0696.

Nine Mile Point Unit 2 Position

Refer to Section 18.2 for the Unit 2 NUREG-0737 position.

Unit 2 has provided a commitment to follow the guidance provided by Supplement 1 to NUREG-0737 in Unit 2 Letter No. 6438, dated April 14, 1983, to D. G. Eisenhut, Director, Division of Licensing of the NRC.

I.G.1 TRAINING DURING LOW-POWER TESTING

FSAR Cross-Reference

Sections 13.2, 14.2

NUREG-0737 Position[6]

The objective is to increase the capability of the shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted. Near-term operating license facilities will be required to develop and implement intensified training exercises during the low-power testing programs. This may involve the repetition of startup tests on different shifts for training purposes. Based on experiences from the near-term operating license facilities, requirements may be applied to other new facilities or incorporated into the plant drill requirement (Task I.A.2.5). Review comprehensiveness of test programs.

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[6]Text of NUREG position can be found in NUREG-0660.

The Office of Nuclear Reactor Regulation will require new operating licensees to conduct a set of low-power tests to accomplish the requirement. The set of tests will be determined on a case-by-case basis for the first few plants. Then the Office of Nuclear Reactor Regulation will develop acceptance criteria for low-power test programs to provide hands-on training for plant evaluation and off-normal events for each operating shift. It is not expected that all tests will be required to be conducted by each operating shift. Observation by one shift of training of another shift may be acceptable.

The Office of Nuclear Reactor Regulation will develop criteria in conjunction with initial near-term operating license reviews.

Licensees will: 1) define training plan prior to loading fuel, and 2) conduct training prior to full-power operation.

Nine Mile Point Unit 2 Position

The conduct of the initial startup and test program including preoperational testing and startup testing is described in Chapter 14. Personnel training is described in Section 13.2. The training described includes the use of a plant-specific simulator and meets the intent of this TMI action item.

Operator training by exposure to operational and testing evolutions is inherent in the integrated testing program being performed at Unit 2.

Integrated ECCS testing, typical cold and hot functional tests, and startup tests including loss of power with or without simulated LOCAs, will be possible on the Unit 2 plant-specific simulator.

The simulator training program will provide all shift personnel with experience in evolutions scheduled, not just those in which they participate during the plant testing phases. These evolutions can be repeated to allow various aspects and responses to be emphasized and test procedures to be critiqued. Documentation of Operations personnel participation in these training evolutions is required as part of the Operator training program.

II.B.1 REACTOR COOLANT SYSTEM VENTS

FSAR Cross-Reference

Sections 5.1, 5.2

NUREG-0737 Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated

from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a LOCA or a challenge to containment integrity. Since these vents form a part of the RCPB, the design of the vents shall conform to the requirements of Appendix A to 10CFR50, General Design Criteria. The vent system shall be designed with sufficient redundancy to assure a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

1. Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCAs initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10CFR50.46.

2. Submit procedures and supporting analysis for Operator use of the vents that also include the information available to the Operator for initiating or terminating vent usage.

The important safety function enhanced by this venting capability is core cooling. For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of noncondensable gas which could interfere with core cooling.

Procedures addressing the use of the RCS vents should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant's capability to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the normal design basis must not result in a violation of the requirements of 10CFR50.44 or 10CFR50.46.

The size of the reactor coolant vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly broad spectrum of sizes. The criteria for sizing a vent can be developed in several ways. One approach that may be considered is to specify a volume of noncondensable gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

Where practical, the RCS vents should be kept smaller than the size corresponding to the definition of LOCA (10CFR50, Appendix A). This will minimize the challenges to the ECCS since the

inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond Technical Specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve-in-series valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

A positive indication of valve position should be provided in the control room.

The reactor coolant vent system shall be operable from the control room.

Since the RCS vent will be part of the RCPB, all requirements for the RCPB must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures may be a viable option to meet the single-failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10CFR50.46.

The probability of a vent path failing to close, once opened, should be minimized; this is a new requirement. Each vent must have its power supplied from an emergency bus. A single failure within the power and control aspects of the reactor coolant vent system should not prevent isolation of the entire vent system when required. On BWRs, block valves are not required in lines with safety valves that are used for venting.

Vent paths from the primary system to within containment should go to those areas that provide good mixing with containment air.

The reactor coolant vent system (i.e., vent valves, block valves, position indication devices, cable terminations, and piping) shall be seismically- and environmentally-qualified in accordance with IEEE-344-1975 as supplemented by RG 1.100 and RG 1.92, and Standard Review Plan (SRP) 3.9.2, 3.9.3, and 3.10. Environmental qualifications are to be in accordance with the May 23, 1980, Commission Order and memorandum (CLI-80-21).

Provisions to test for operability of the reactor coolant vent system should be part of the design. During the First Ten-Year Interval, testing was performed in accordance with Subsection IWV of Section XI, the 1983 Edition with the Summer 1983 Addenda. During the Second Ten-Year Interval and subsequent intervals, inservice testing will be in accordance with 10CFR50.55a and the IST program plan.

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.

Specific BWR Design Considerations

Since the BWROG has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWROG. In addition, the ability of these systems to meet the same requirements as the PWR vent system must be documented.

In addition to RCS venting, each BWR licensee should address the ability to vent other systems, such as the isolation condenser which may be required to maintain adequate core cooling. If the production of a large amount of noncondensable gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

The Unit 2 design philosophy is in agreement with the BWROG position on this subject, which is described in detail in NEDO-24782[2].

Nine Mile Point Unit 2 Position

The Unit 2 design includes 18 main steam SRVs, of which 7 are used for ADS. Redundant divisional power is supplied to the ADS valves. The discharge lines from the ADS valves (as well as the discharge lines from the 11 non-ADS SRVs) run individually to the suppression pool. The ADS valves and discharge lines satisfy the NUREG-0737 requirements for RCS venting.

In addition to the ADS valves, RCS venting can also take place through the RCIC system which directs steam from one of the main steam lines to a turbine-driven pump; the steam then exhausts from the turbine to the suppression pool. The RCIC system can serve as a vent path during hot standby or during reactor isolation.

The reactor vessel top head vent line can also be used to direct steam and noncondensable gases from the reactor upper dome to the

suppression pool. Two Class 1E divisionally-powered motor-operated valves (MOVs) are located in series on this line. These MOVs are operated remote manually from the main control room. The reactor vessel top head vent line can be operated over the range of plant operations from cold shutdown through full power operation. This line is used principally to vent the reactor during the final stages of normal shutdown from power operation.

Each RHR heat exchanger is equipped with a shellside (RHR side) vent line, which is routed back to the suppression pool. These lines are each provided with two Class 1E divisionally-powered MOVs, located in series, which are operated remote manually from the main control room. These lines may be used at any time, including post-LOCA operation.

The BWROG developed the following position with regard to a potential break in a vent line: "The result of a break in the safety-relief valve discharge line, or any of the other systems enumerated above, would be the same as a small steam line break. A complete steam line break is part of the plant's design basis, and smaller-sized breaks have been shown to be of lesser severity...Thus, no new analyses to show conformance with 10CFR50.46 are required." The BWROG also developed the following position regarding operating procedures for ADS and RCIC for vent purposes:

"Under most circumstances, there would be no choice as to where to vent to or when to vent, since the relief valves (as part of the automatic depressurization system)...and RCIC [ICS] will function automatically in their designed modes to ensure adequate core cooling, and these will provide continuous venting to the suppression pool. The current assessment is that it would not be desirable to interfere with emergency core cooling functions in order to prevent venting."

II.B.2 PLANT SHIELDING/POST-ACCIDENT ACCESS TO VITAL AREAS

<u>FSAR Cross-Reference</u>

Sections 3.11, 12.1, 12.2, 12.3

<u>NUREG-0737 Position</u>

With assumption of a post-accident release of radioactivity equivalent to that described in RG 1.3 and RG 1.4 (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, MCCs,

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 and 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.

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. These 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 that 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 the purposes of this evaluation, vital areas and equipment are not necessarily the same vital areas or equipment defined in 10CFR73.2 for security purposes. The security center is listed as an area to be considered potentially vital, since access to this area may be necessary to gain access to other areas in the plant.

The control room, TSC, sampling station, and sample analysis area must be included among those areas where access is considered vital after an accident. (See Task III.A.1.2 for discussion of the TSC and Emergency Operations Facility [EOF].) The evaluation to determine the necessary vital areas should also include, but not be limited to, consideration of the post-LOCA hydrogen control system, containment isolation reset control area, manual ECCS alignment area (if any), MCCs, instrument panels, emergency power supplies, security center, and radwaste control panels. Dose rate determinations need not be noted for these areas if they are not considered vital.

As a minimum, necessary modifications must be sufficient to provide for vital system operation and for occupancy of the control room, TSC, sampling station, and sample analysis area.

To ensure 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. <u>Source Term</u> The minimum radioactive source term should be equivalent to the source terms recommended in RG 1.3, 1.4, and 1.7 and SRP 15.6.5 with appropriate decay times based on plant design (i.e., the radioactive

decay that occurs before fission products can be transported to various systems can be assumed).

a. <u>Liquid-Containing Systems</u> 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 RHR, high-pressure coolant injection (HPCI), and LPCI, or the equivalent of these systems. In determining the source term for recirculated, depressurized cooling water, it can be assumed that the water contains no noble gases.

b. <u>Gas-Containing Systems</u> 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., BWR steam lines), the concentration of radioactivity shall be determined, assuming the activity is contained in the vapor space in theprimary coolant system.

2. <u>Systems Containing the Source</u> Systems assumed in the analysis to contain high levels of radioactivity in a post-accident situation should include, but not be limited to, containment, RHR system, safety injection systems, chemical and volume control system (CVCS), containment spray recirculation system, sample lines, gaseous radwaste systems, and SGTS (or equivalent of these systems). If any of these systems or others that could contain high levels of radioactivity were excluded, 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 Task III.D.1.1. Liquid waste systems need not be included in this analysis. Modifications to liquid waste systems will be considered after completion of Task III.D.1.4.

3. <u>Dose Rate Criteria</u> The design dose rate for personnel in a vital area should be such that the guidelines of GDC 19 will not be exceeded during the course of the accident. GDC 19 requires that adequate radiation protection be provided so that the dose to personnel would 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, 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 <u>not</u> to be used to limit access in the event of an accident.

a. <u>Areas Requiring Continuous Occupancy</u> Less than 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 TSC are areas where continuous occupancy will be required. The dose rate for these areas is based on the control room occupancy factors contained in SRP 6.4.

b. <u>Areas Requiring Infrequent Access</u> 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, MCC, instrumentation locations, and reactor coolant and containment gas sample stations are examples of sites where occupancy may be needed often, but not continuously.

4. <u>Radiation Qualification of Safety-Related Equipment</u> The review of safety-related equipment that may be unduly degraded by radiation during post-accident operation of this equipment relates to equipment inside and outside the primary containment. Radiation source terms calculated to determine environmental qualification of safety-related equipment consider the following:

a. LOCA events that 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 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 particulates 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	(100/50/1) in RCS	(10/10/0) in RCS
Inside	Larger of 100/50/1) in containment or (100/50/1) in RCS	(10/10/0) in RCS

Nine Mile Point Unit 2 Position

Analyses have been performed to quantify the post-accident radiation levels throughout the Unit 2 plant based upon the source terms presented below.

These radiation conditions are being used in conjunction with other environmental conditions (pressure, temperature, and humidity) for the equipment qualification program. Safety-related equipment is being qualified in accordance with NUREG-0588.

A description of the Unit 2 post-accident shield design review is given in Section 12.3.1.3. Areas where access is vital after an accident are analyzed for personnel occupancy to ensure that doses to personnel performing vital post-accident functions are less than GDC 19 limits. This information is provided in Table 12.3-3. A dose rate map for potentially-occupied areas is provided on Figure 12.3-69 and corresponding Table 12.3-4.

Source Term

Radioactive source release and distribution assumptions for Unit 2 are as follows.

Radioactive Source Release

1. The percentages of core inventory radioactive fission products assumed to be released from the fuel rods are:

Noble gases (Kr, Xe)	100%
Halogens	50%
Others	1%
Cesium	50%

2. This entire release is assumed to occur instantaneously at the start of the accident.

Radioactive Source Distribution

To envelop the full spectrum of break sizes and depressurization rates, two bounding events and source distributions were considered.

1. LOCA The following fission products are considered to be uniformly mixed in the following volumes:

   a. Suppression Pool and Reactor Coolant System

Noble gases	0%
Halogens	50%
Others	1%
Cesium	50%

   This distribution assumes short-term reactor depressurization and is consistent with a scenario which leads to gross fission product release from the fuel.

   b. Combined Drywell/Wetwell Air Space

Noble gases	100%
Halogens	50%[7]

   Using this distribution, time-history radiation zones are established throughout the Unit 2 plant as follows:

   a. The above sources will be distributed in the following system piping to establish time-history radiation zones for the primary containment and reactor building. These systems were conservatively assumed to operate concurrently.

[7]The fraction of airborne halogens available for release to the environment is 25 percent of the core inventory in accordance with RG 1.3. This percentage is further reduced due to suppression pool scrubbing credit in accordance with SRP Section 6.5.5.

(1) Main steam system (primary only).
(2) RCIC.
(3) RHR.
(4) LPCS and HPCS.
(5) SGTS.
(6) RCS/RWCU (primary only).
(7) Containment atmosphere monitoring.
(8) Hydrogen recombiner system.

b. In addition to radiation shine from system piping and components, the primary containment is assumed to leak at Technical Specification limits resulting in an airborne source term that is included in the radiation zoning.

c. For areas outside the reactor building, the following sources are considered:

(1) Airborne releases, including bypass leakage, post-accident SGTS effluent, ESF equipment leakage, and secondary containment overpressurization. Pertinent data for these release scenarios are provided in Table 15.6-13.

(2) Direct radiation from secondary containment.

(3) Air-scattered radiation from secondary containment (sky shine).

2. <u>Pipe Break in Reactor Building</u> The temperature and pressure transients resulting as a consequence of this accident are insufficient to cause fuel damage (see Section 6.3). Therefore, the activity available for release from the break is the reactor coolant and steam that are released prior to system isolation. In addition, the iodine concentrations are normalized to the maximum Technical Specification limit of 4 uCi/gm I-131 dose equivalent to account for spiking.

II.B.3 POST-ACCIDENT SAMPLING

<u>FSAR Cross-Reference</u>

Section 9.3.2

<u>Elimination of Post-Accident Sampling System (PASS) Requirements</u>

The results of BWROG Topical Report NEDO-32991-A, "Regulatory Relaxation for BWR Post-Accident Sampling Stations (PASS)," dated August 2001, confirmed that the BWR PASS does not provide the benefits expected by the NRC when the requirements were promulgated following the Three Mile Island Unit 2 accident. All BWR emergency and severe accident response strategies can be

implemented using in-plant instrumentation, without reliance on the PASS. Moreover, operating experience has demonstrated that in-plant instrumentation and the associated analysis methods will provide the timely information required to assess core damage and mitigate severe accidents. This information is available from in-plant instrumentation early in the accident scenario and the derived information is as good as or better than information currently provided by the PASS several hours after initiation of the event. In addition, the BWROG issued NEDC-33045P, "Methods of Estimating Core Damage in BWRs," dated July 2001, which relies only on installed plant instrumentation (no reliance on the PASS) for core damage assessment following a severe accident. The BWROG has, therefore, concluded that the PASS can be removed without significantly affecting plant safety and recommended that all PASS regulatory requirements be eliminated.

Accordingly, as documented in License Amendment No. 106 (NRC letter from P. S. Tam to J. T. Conway dated August 9, 2002), the requirements to have and maintain a PASS at NMP2 were eliminated. As such, the following information related to NUREG-0737, Section II.B.3, is maintained for historical purposes only.

<u>NUREG-0737 Position</u>

The PASS is evaluated for compliance with NUREG-0737, Section II.B.3. These 11 criteria and clarifications have been copied verbatim from NUREG-0737. A general description of the system has been included in Position 1.

<u>Criterion 1</u>

The licensee 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.

<u>Clarification 1</u>

Provide information on sampling(s) and analytical laboratories locations including a discussion of relative elevations, distances and methods for sample transport. Responses to this item should also include a discussion of sample recirculation, sample handling and analytical times to demonstrate that the three-hour time limit will be met (see item 6 below relative to radiation exposure). Also describe provisions for sampling during LOOP (i.e., designate an alternative backup power source, not necessarily the vital (Class IE) bus, that can be energized in sufficient time to meet the 3-hr sampling and analysis time limit).

<u>Position 1</u>

PASS is designed to obtain representative liquid and gas samples from within the primary containment for radiological analysis in

association with the possible consequences of a LOCA. The system consists of: 1) a piping station located in the reactor building, el 250 ft; 2) a sampling station located in the radwaste sample room, el 261 ft; 3) two control panels situated approximately 10 ft from the sample station in the sample room; 4) assorted transport equipment; 5) a ventilation system; and 6) assorted interconnecting tubing.

The underlying design philosophy is to minimize exposure by minimizing the required sample sizes, to optimize the weight of shielded sample containers to facilitate movement through potentially high-level radiation areas, and to provide adequate shielding at the sample station and in the laboratory. The system is also designed to provide useful samples under all conditions ranging from normal shutdown and power operation to a full LOCA with fission product releases consistent with RG 1.3. A local area radiation monitor is provided to inform the Operator of the ambient radiation level. The PASS flow diagram is shown on Figure II.B.3-1a.

Provision has been made to obtain gas samples from both the drywell and wetwell atmospheres and from the secondary containment atmosphere. The sample system is designed to operate over the range of potential pressures starting at 1 hr after a LOCA. Heat-traced sample lines are used to prevent precipitation of moisture and resultant loss of iodine in the sample lines. The gas samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and total iodine activity by subsequent counting of the samples on a gamma spectroscopy system.

Alternately, the sample flow can bypass the iodine sampler and be chilled to remove moisture. A 15-ml grab sample can then be taken for determination of gaseous activity and for gas composition by gas chromatography. This size sample has been adopted to be consistent with present offgas sample vial counting factors. Provision will be made in the laboratory to aliquot fractions of the initial vial contents to other vials if the activity is too high to count directly.

A sample line is provided to obtain reactor coolant samples from two points in the jet pump pressure instrument system when the reactor is at pressure. This sample location was chosen over the normal reactor sample points as the reactor cleanup system is expected to be isolated under accident conditions, and it is possible that the recirculation line containing the normal reactor water sample lines may not be representative. The jet pump pressure instrumentation system has been determined to be an optimum sample point for accident conditions. The pressure taps are well protected from potential damage and debris. There is normally excellent natural circulation of the bulk of the coolant past these taps, and the pressure taps are located sufficiently low to permit sampling at a reactor water level below the lower core support plate.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode.

All liquid samples are taken into septum bottles mounted on sampling needles. The sample panel is basically a bypass loop on the sample purge line. In the normal lineup, the sample flows through a conductivity cell (readable range 0.1 to 1000 micromhos/cm), and then through a ball valve bored out to 0.10-ml volume. Flow through the sample panel is established, the valve is rotated 90°, and a syringe is used to flush the sample plus a measured volume of diluent (generally 10 ml) through the valve and into the sample bottle. This provides an initial dilution of 100:1 and supplies a sample for further dilution and subsequent counting on a gamma spectrometer. Alternately, the sample flow can be diverted through a cylinder to obtain a large pressurized volume of coolant. This volume can be circulated and depressurized into a gas sampling chamber. The pressure of the collected gas can be related to total dissolved gas concentration. A sample of the gas can be obtained for H_2O and O_2 analysis. Ten-ml aliquots of the degassed liquid can also be taken for offsite chemical analyses requiring a relatively large sample. A radiation monitor in the liquid sample enclosure monitors liquid flow from the sample station to provide immediate assessment of the sample activity level. This monitor also provides information as to the effectiveness of the demineralized water flushing of the sample system following sample operation.

The piping station includes sample coolers and control valves which select liquid sample points. The sample station consists of a wall-mounted frame and enclosures. Included within the sample station are equipment trays which contain modularized liquid and gas samplers. Each of these modules is approximately 18 in x 14 in x 20 in high. The lower liquid sample portion of the sample station is shielded with 6 in of lead brick, whereas the upper gas sampler requires 2 in of lead. The total weight of the wall-mounted portion of the system is approximately 7,000 lb. The dimensions of the sample station including shielding are approximately 29 in wide x 27 in deep x 72 in high. The frame is mounted so that the bottom of the frame is approximately 20 in off the floor. The control instrumentation is installed in a 2 ft x 4 ft x 6 ft high standard control cabinet panel. The panel contains the conductivity, radiation level readouts, and the flow, pressure, and temperature indicators, and various control valves and switches. The general front panel arrangement is shown on Figure II.B.3-2.

Appropriate sample handling tools are provided at the sample station. A gas sampler vial positioner and gas vial cask are included. The gas vial is installed and removed by use of the vial positioner through the front of the gas sampler. The vial

is then manually dropped into the cask with the positioner which allows the vial to be maintained about 3 ft from the individual performing the operation.

The small volume liquid sample is remotely obtained through the bottom of the sample station by use of the small volume cask and cask positioner. The cask positioner holds the cask and positions the cask directly under the liquid sampler.

The sample vial is manually raised within the cask to engage the hypodermic needles. When the sample vial has been filled, the bottle is manually withdrawn into the cask. The sample vial is always contained within lead shielding during this operation. The cask is then lowered and sealed prior to transport to the laboratory.

A large volume cask and cask positioner are used to remotely obtain the large volume liquid sample. The positioner contains the cask and vial.

The cask is transported to the required position under the sample station by a four-wheel dolly cask positioner. When in position, this cask is hydraulically elevated approximately 1.5 in by a small hand pump for contact with the sample station shielding under the liquid sample enclosure. The sample bottle is raised, held, and lowered by a simple push/pull cable. The cask is sealed by a threaded top plug inserted above the sample bottle. The weight of this large volume cask is approximately 700 lb. The cask may be used for offsite shipment of the large volume sample; however, it will require additional packaging.

A 15-ml bottle is contained within the lead-shielded cask. This sample bottle is raised from its location in the cask to the sample station needles for bottle filling. The sample station will only deliver 10 ml to this sample bottle. When filled, the bottle is withdrawn into the cask. The sample bottle is always shielded by 5 to 6 in of lead when in position under the sample station and during the fill and withdraw cycles; thus, Operator exposure is controlled.

The particulate filters and iodine cartridges are removed via a drawer arrangement. The quantity of activity which is accumulated on the cartridges is controlled by a combination of flow orificing and time sequence control of the flow valve opening; in addition, the deposition of iodine is monitored during sampling using a radiation detector installed adjacent to the cartridge. These samples are limited to activity levels which will not require shielded sample carriers to transport the samples to the laboratory.

The chemistry laboratory and counting room to be used for post-accident analysis are located in Unit 1 on el 261 ft. The sample transport route to the Unit 1 chemistry room will be from the radwaste sample room, el 261 ft, west to the southeast corner

of the screenhouse, then south into the turbine building, el 250 ft, via the truck ramp. The transport route includes the truck aisle that lies to the north and west of the condensers, and the access passage to Unit 1. Once in the Unit 1 shop room, an elevator provides transportation to el 261 ft, where the chemistry laboratory is located. The total distance is approximately 1,000 ft. Table II.B.3-1 shows the times required for sampling, transport, and analysis. The total time is within the 3-hr limit, with the exception of chloride analysis of reactor coolant, which is completed within the 96-hr time limit.

The PASS isolation valve control panel (2CES-PNL555) and the PASS sample station control panel (2SSP-IPNL102) are operated from the plant normal UPS (2VBS-PNLA102 and B107), which is backed up by the plant 125-V dc normal battery system. Both the UPS system and the battery chargers are connectable to the standby diesel generators, except under LOCA conditions.

Criterion 2

The licensee shall establish an onsite radiological and chemical analysis capability to provide, within 3-hr time frame established above, quantification of the following:

1. 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);

2. Hydrogen levels in the containment atmosphere;

3. Dissolved gases (e.g., H^2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

4. Alternatively, have in-line monitoring capabilities to perform all or part of the above analyses.

Clarification 2

1. A discussion of the counting equipment capabilities is needed, including provisions to handle samples and reduce background radiation to minimize personnel radiation exposures (ALARA). Also, a procedure is required for relating radionuclide concentrations to core damage. The procedure should include:

   a. Monitoring for short- and long-lived volatile and nonvolatile radionuclides (see Vol. II, Part 2, pp. 524-527 of Rogovin report for further information).

   b. Provisions to estimate the extent of core damage based on radionuclide concentrations and taking

into consideration other physical parameters such as core temperature data and sample location.

2. Show a capability to obtain a grab sample, transport and analyze for hydrogen.

3. Discuss the capabilities to sample and analyze for the accident sample species listed here and in RG 1.97, Rev. 2.

4. Provide a discussion of the reliability and maintenance information to demonstrate that the selected on-line instrument is appropriate for this application. (See (8) and (10) below relative to backup grab sample capability and instrument range and accuracy).

<u>Position 2</u>

Response: (2)

The reactor coolant and containment atmosphere samples from the PASS can be analyzed for major fission product concentrations by gamma ray spectral analysis. The samples may be diluted by a factor of up to 10^6 to obtain activities permitting isotopic analysis on a germanium crystal detector. The samples are handled using long tongs and lead brick shielding to reduce radiation exposure to a level ALARA. The concentrations of Kr-85, I-131, Cs-137, and Xe-133 are corrected for dilution, decay, temperature, and pressure to the time of reactor shutdown. The extent of fuel damage can then be determined directly from the figures provided in the plant emergency procedures.

Hydrogen levels in the containment can be measured by the CAM system. The hydrogen analyzer is environmentally qualified in accordance with RG 1.89 to operate satisfactorily following a LOCA. The hydrogen concentration is recorded in the main control room.

Alternatively, a grab sample of the containment atmosphere can be obtained by the PASS and analyzed for hydrogen concentration by using a gas chromatograph.

Boron content of reactor coolant can be determined by analyzing the diluted reactor coolant sample by the carminic acid method. The sample is handled in the laboratory with long tongs and lead brick shielding to reduce radiation exposure.

Total dissolved gas levels in the reactor coolant can be determined by measuring the pressure of the gas collected from a degassed sample of coolant.

A sample of the dissolved gases can be obtained and analyzed for hydrogen or oxygen content using a gas chromatograph.

pH can be measured by use of a flat surface combination pH electrode on 0.1 to 0.3 ml of reactor coolant. The sample can be collected by operating the diluted reactor coolant sampler of the PASS several times without adding dilution water.

Chloride in the reactor coolant can be determined, within 96 hr, by using a specific ion electrode. An undiluted reactor coolant sample is treated with a sodium bromate-nitric acid solution to eliminate halogen interferences. The sample is handled in a fume hood with long tongs and lead brick shielding to reduce radiation exposure.

Criterion 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 [RWCU]) to be placed in operation in order to use the sampling system.

Clarification 3

System schematics and discussions should clearly demonstrate that post-accident sampling, including recirculation, from each sample source is possible without use of an isolated auxiliary system. It should be verified that valves which are not accessible after an accident are environmentally qualified for the conditions in which they must operate.

Position 3

Isolated auxiliary systems are not required for post-accident sampling of reactor coolant or containment atmospheres. The sample lines for containment atmosphere samples connect into the containment monitoring system (CMS) outside of containment isolation valves on both hydrogen analyzer loops. These hydrogen analyzers are operational post-accident, with the containment isolation valves open. The sample lines for reactor coolant connect to two systems. There are no isolation valves between the reactor vessel and the sample taps into the jet pump instrumentation lines; therefore, a sample is available upon opening the PASS isolation valves. The residual heat removal system (RHS) is also operational post-accident which allows sampling upon opening the RHS sampling valves (operated from the main control room) and the PASS isolation valve.

The atmosphere samples are obtained by operating a gas pump inside the PASS while coolant samples are obtained by system pressure.

The PASS isolation valves are environmentally qualified to IEEE-323-1974 and IEEE-382-1972. All the components located in the PASS piping station in the secondary containment have been selected to assure that materials in these components will

withstand the thermal and radiation environment expected during PASS operation.

Criterion 4

Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended, but is not mandatory.

Clarification 4

Discuss the method whereby total dissolved gas or hydrogen and oxygen can be measured and related to reactor coolant system concentrations. Additionally, if chlorides exceed 0.15 ppm, verification that dissolved oxygen is less than 0.1 ppm is necessary. Verification that dissolved oxygen is <0.1 ppm by measurement of a dissolved hydrogen residual of $\geq$10 cc/kg is acceptable for up to 30 days after the accident. Within 30 days, consistent with minimizing personnel radiation exposures (ALARA), direct monitoring for dissolved oxygen is recommended.

Position 4

Total dissolved gas levels in the reactor coolant can be determined by measuring the pressure of the gas collected from a degassed sample of coolant. The sample flow in the PASS is diverted through a cylindrical volume. The volume is then circulated and depressurized into a gas chamber. The total dissolved gas level is determined from the pressure developed in the chamber. A sample of the gas can also be obtained for H_2 and O_2 analysis.

Criterion 5

The time for a chloride analysis to be performed depends upon two factors: a) if the plant's coolant water is seawater or brackish water, and b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 hr of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

Clarification 5

BWRs on sea or brackish water sites, and plants which use sea or brackish water in essential heat exchangers (e.g., shutdown cooling) that have only single barrier protection between the reactor coolant are required to analyze chloride within 24 hr. All other plants have 96 hr to perform a chloride analysis.

Samples diluted by up to a factor of 1,000 are acceptable as initial scoping analysis for chloride, provided 1) the results are reported as ±2 ppm Cl (the licensee should establish this value; the number in the blank should be no greater than 10.0 ppm Cl) in the reactor coolant system, and 2) that dissolved oxygen can be verified at <0.1 ppm, consistent with the guidelines above in Clarification No. 4. Additionally, if chloride analysis is performed on a diluted sample, an undiluted sample need also be taken and retained for analysis within 30 days, consistent with ALARA.

Position 5

Chloride in the reactor coolant can be determined within 96 hr by using a specific ion electrode. Unit 2 does not use brackish water for plant coolant. An undiluted reactor coolant sample is treated with a sodium bromate-nitric acid solution to eliminate halogen interferences. The sample is handled in a fume hood with long tongs and lead brick shielding to reduce radiation exposure.

Additionally, Unit 2 participates in the Pooled Inventory Management Program and should have a post-accident sampling cask from Nuclear Packaging, Inc., available for sample transport to an offsite facility for further analysis.

Criterion 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 the criteria of GDC 19 (Appendix A, 10CFR50), i.e., 5 rem whole body, 75 rem extremities. (Note that the design and operational review criterion was changed from the operational limits of 10CFR20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees).

Clarification 6

Consistent with RG 1.3 or 1.4 source terms, provide information on the predicted personnel exposures based on person-motion for sampling, transport and analysis of all required parameters.

Position 6

As shown in Table II.B.3-1, whole body exposure and extremity exposure[8] would be less than 0.98 R and 16 R, respectively. Individual exposure would be at even lower levels because more than one person would be performing the required tasks.

[8] The referenced exposures are based on a power level of 3,323 MWt. Due to power uprate to 3,467 MWt, the exposure values shown must be multiplied by a factor of 1.0136.

Criterion 7

The analysis of primary coolant samples for boron is required for PWRs. (Note that RG 1.97 Revision 2 specifies the need for primary coolant boron analysis capability at BWR plants.)

Clarification 7

PWRs need to perform boron analysis. The guidelines for BWRs are to have the capability to perform boron analysis, but they do have to do so unless boron was injected.

Position 7

Boron concentration in the primary coolant can be determined by the carminic acid method of analysis on the diluted reactor coolant samples. Reactor coolant flows into the PASS through a ball valve bored out to 0.10 ml. The valve is rotated 90 degrees, and a syringe is used to flush the sample plus 10 ml of demineralized water into a sample bottle. The bottle is transported to the laboratory in a lead-shielded cask. The sample is handled in the laboratory with tongs and lead brick shielding to reduce radiation exposure.

Criterion 8

If in-line monitoring is used for any sampling and analytical capability specified herein, the licensee 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.

Clarification 8

A capability to obtain both diluted and undiluted backup samples is required. Provisions to flush in-line monitors to facilitate access for repair is desirable. If an offsite laboratory is to be relied on for the backup analysis, an explanation of the capability to ship and obtain analysis for one sample per week thereafter until accident condition no longer exists should be provided.

Position 8

The PASS can obtain both diluted and undiluted reactor coolant, dissolved gas, and containment atmosphere samples. In-line monitoring is used to determine hydrogen levels in the containment atmosphere; however, a grab sample can be obtained and analyzed for hydrogen on a gas chromatograph as a backup. No offsite laboratories are relied upon for backup analysis.

However, Unit 2 participates in the Pooled Inventory Management Program and should have a post-accident sampling cask from Nuclear Packaging, Inc., available for sample transport to an offsite facility.

Criterion 9

The licensee's radiological and chemical sample analysis capability shall include provisions to:

1. Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in RG 1.3 or 1.4 and 1.7. 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 uCi/g to 10 Ci/g.

2. 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 a ventilation system design which will control the presence of airborne radioactivity.

Clarification 9

1. Provide a discussion of the predicted activity in the samples to be taken and the methods of handling/dilution that will be used to reduce the activity sufficiently to perform the required analysis. Discuss the range of radionuclide concentration which can be analyzed for, including an assessment of, the amount of overlap between post-accident and normal sampling capabilities.

2. State the predicted background radiation levels in the counting room, including the contribution from samples which are present. Also provide data demonstrating what the background radiation levels and radiation effect will be on a sample being counted to assure an accuracy within a factor of 2.

Position 9

Under severe accident conditions, the design basis activity level of the reactor coolant sample is 6.9 E-3 Ci/gm. The 0.1 ml of

primary coolant diluted to 10.0 ml at the PASS would be used for the initial sample. The sample would be placed in a lead container for transport to the laboratory. A calibrated syringe would be used to obtain an aliquot for further dilution. A dilution factor of 10^6 can be obtained for isotopically analyzing samples up to 10 Ci/gm.

Direct counting of the initial 100:1 dilution sample would permit analysis down to 10 uCi/gm. In addition, the degassed 10-ml sample available from the PASS provides a method to obtain samples in the 10^{-2} to 10^{-3} uCi/gm levels which are encountered during normal operation. The PASS can provide useful samples at coolant activities ranging from 10 Ci/gm to well below the maximum level that can be tolerated at the normal reactor sample station.

The counting room used for post-accident sampling analysis is located in Unit 1. It is surrounded by concrete walls approximately 3 ft thick. The emergency ventilation system inlet duct for this room is 1500 ft from the Unit 2 stack. It has particulate filters. Assuming containment isolation, background radiation levels are predicted to be ≤.3 mrem/hr.

To demonstrate the effect of background radiation, a Cs-137 source was counted with a 5 mR/hr background level from a Eu-152 source. The Cs-137 was counted with an accuracy of 10 percent, which is well within the factor of 2 requirement.

Criterion 10

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.

Clarification 10

The recommended ranges for the required accident sample analyses are given in RG 1.97 Revision 2. The necessary accuracy within the recommended ranges is as follows:

1. Gross activity, gamma spectrum: Measured to estimate core damage, these analyses should be accurate within a factor of 2 across the entire range.

2. Boron: Measured to verify shutdown margin.

   In general, this analysis should be accurate within ± 5% of the measured value (i.e., at 6,000 ppm B the tolerance is ±300 ppm while at 1,000 ppm B the tolerance is ±50 ppm). For concentrations below 1,000 ppm, the tolerance band should remain at ±50 ppm.

3. Chloride: Measured to determine coolant corrosion potential.

For concentrations between 0.5 and 20.0 ppm chloride, the analysis should be accurate within ±10% of the measured value. At concentrations below 0.5 ppm, the tolerance band remains at ±0.05 ppm.

4. Hydrogen or Total Gas: Monitored to estimate core degradation and corrosion potential of the coolant.

   An accuracy of ±10% is desirable between 50 and 2000 cc/kg but ±20% can be acceptable. For concentration below 50 cc/kg, the tolerance remains at ±5.0 cc/kg.

5. Oxygen: Monitored to assess coolant corrosion potential.

   For concentrations between 0.5 and 20.0 ppm oxygen, the analysis should be accurate within ±10% of the measured value. At concentrations below 0.5 ppm, the tolerance band remains at ±0.05 ppm.

6. pH: Measured to assess coolant corrosion potential.

   Between a pH of 5 to 9, the reading should be accurate within ±0.3 pH units. For all other ranges, ±0.5 pH units is acceptable.

   To demonstrate that the selected procedures and instrumentation will achieve the above-listed accuracies, it is necessary to provide information demonstrating their applicability in the post-accident water chemistry and radiation environment. This can be accomplished by performing tests utilizing the standard test matrix provided below or by providing evidence that the selected procedure or instrument has been used successfully in a similar environment.

STANDARD TEST MATRIX FOR UNDILUTED REACTOR COOLANT SAMPLES IN A POST-ACCIDENT ENVIRONMENT

Constituent	Nominal Concentrations (ppm)	Added as (chemical salt)
I-	40	Potassium iodide
Cs+	250	Cesium nitrate
Ra+2	10	Barium nitrate
La+3	5	Lanthanum chloride
Ce+4	5	Ammonium cerium nitrate
CL-	10	
B	2000	Boric acid
Li±	2	Lithium hydroxide
NO_3	150	
NH_4	5	
K+	20	
Gamma radiation (induced field)	Adsorbed dose (Later) rad/gm of reactor coolant	

NOTES:

1. Instrumentation and procedures which are applicable to diluted samples only should be tested with an equally diluted chemical test matrix. The induced radiation environment should be adjusted commensurate with the weight of actual reactor coolant in the sample being tested.

2. For PWRs, procedures which may be affected by spray additive chemicals must be tested in both the standard test matrix plus appropriate spray additives. Both procedures (with and without spray additives) are required to be available.

3. For BWRs, if procedures are verified with boron in the test matrix, they do not have to be tested without boron.

4. In lieu of conducting tests utilizing the standard test matrix for instruments and procedures, provide evidence that the selected instrument or procedure has been used successfully in a similar environment.

All equipment and procedures which are used for post-accident sampling and analyses should be calibrated or tested at a frequency which will ensure, to a high degree of reliability, that it will be available if required. Operators should receive initial and refresher training in post-accident sampling, analysis and transport. A minimum frequency for the above efforts is considered to be every 6 months if indicated by testing. These provisions should be submitted in revised Technical Specifications in accordance with Enclosure 1 of NUREG-0737. The staff will provide model Technical Specifications at a later date.

Position 10

The suitability of each method used for analysis was evaluated. A summary is presented in Table II.B.3-2. In order to ensure the stated accuracies are achievable, technicians are regularly trained in the various tasks. Additionally, the various analytical and sampling instrumentation is calibrated.

Technician training consists of an initial 2-day program. Retraining of technicians occurs during plant emergency drills during which various samples are obtained and analyzed. Process instrumentation is calibrated annually, while a calibration verification of the MCA used is performed three times a week. The spectrometer, pH meter, and gas chromatograph are calibrated before use.

Criterion 11

In the design of the post-accident sampling and analysis capability, consideration should be given to the following items:

1. 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 RCS 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.

2. The ventilation exhaust from the sampling station should be filtered with charcoal absorbers and high-efficiency particulate air (HEPA) filters.

Clarification 11

1. A description of the provisions which address each of these items should be provided. Such items as heat tracing and purge velocities should be addressed. To demonstrate that samples are representative of core conditions, a discussion of mixing, both short and long term, is needed. If a given sample location can be rendered inaccurate due to the accident, i.e., sampling from a hot or cold leg loop which may have a steam or gas pocket, describe the backup sampling capabilities or address the maximum time that this condition can exist.

   BWRs should specifically address samples which are taken from the core shroud area and demonstrate how they are representative of core conditions.

   Passive flow restrictors in the sample lines may be replaced by redundant, environmentally-qualified, remotely-operated isolation valves to limit potential leakage from sampling lines. The automatic containment isolation valves should close on containment isolation or safety injection signals.

2. A dedicated sample station filtration system is not required, provided a positive exhaust exists which is subsequently routed through charcoal absorbers and HEPA filters.

Position 11

Purging capability is provided by two methods:

1. Purging with either demineralized water or nitrogen is available from near the source of the sample in secondary containment to purge the entire PASS from source to discharge.

2. Purging with either demineralized water or nitrogen is available from the radwaste sample room to flush the sample station, piping station, and discharge sample lines. Purging the lines before and after sampling will alleviate cross-contamination of the samples when switching from one sample to another.

Prior to taking a sample, the line volume will be replaced several times, thus ensuring a representative sample.

The sample residue and flush water are returned to the suppression pool. Restriction devices are not used because they are potential crud traps. The small size of the sample lines serves to limit loss of reactor coolant in the case of sample

line rupture. The gas sample lines are heat traced to prevent precipitation of moisture and resultant loss of iodine.

Reactor coolant samples obtained from a tap of the jet pump pressure instrument system will provide representative core coolant samples for accident conditions.

In order to ensure that this sample location provides a representative sample, sufficient core flow is needed to circulate water from the core to the jet pump intake.

After a small break or nonbreak accident, the reactor water level is maintained at or near normal water level by the Operator using emergency procedures. For decay power above 1 percent of rated power, the core flow is estimated to be greater than 10 percent rated flow because of natural circulation. The entire reactor water inventory would be circulated through the jet pumps in about 3 to 4 min, thus ensuring that representative samples of core coolant will be available at the jet pumps.

At power levels of less than 1 percent rated, a sample that is representative of core conditions would be obtained by increasing the reactor water level by 18 in. This will fully flood the standpipes of the moisture separators and will provide a thermally-induced recirculation flow path for mixing.

Makeup water does 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 occurs and the water circulating through the jet pump is representative of reactor coolant inventory for small break or nonbreak accidents.

Further, sample lines in the RHR system provide for a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operating in the shutdown cooling mode.

Finally, for larger line breaks where reactor water level cannot be maintained, reverse flow through the core to the suppression pool is provided. Suppression pool samples are obtained from the RHR pump discharge.

Water is injected into the reactor pressure vessel by the ECCS. The injected water is from the condensate storage tank and/or from the suppression pool. The injected water floods the reactor vessel and flows through the break into the drywell. Water flowing from the reactor vessel pipe break returns to the suppression pool in the drywell downcomer. The RHR system is manually initiated in the pool cooling mode and maintained in this mode unless containment spray is temporarily needed (1 or 2 loops available) to control containment pressure.

The RHR pool cooling system (i.e., suction and return line arrangement in the suppression pool, type of discharge device, etc.,) is designed to assure adequate mixing of the suppression pool.

Based on the RHR pool cooling system design and the communication established between the primary coolant in the reactor water vessel and the suppression pool, the proposed post-accident sampling of water from the RHR suppression pool suction line provides a representative water sample.

Sample capability has been provided for two points in each of the jet pump instrumentation system, the RHR system and the CMS. If anything should go wrong in one loop, the other loop is available for sampling.

The lines are as short as possible, thereby maintaining accessibility to the sample station.

A dedicated charcoal and HEPA filtration system is provided. The small fan is operated on UPS, backed up by the 125-V dc normal battery system. The effluent from the filtration system discharges to the decontamination area ventilation system.

TABLE II.B.3-1
(Sheet 1 of 2)

TIME AND DOSE PROJECTIONS FOR PASS SAMPLING, TRANSPORT, AND ANALYSIS

Task	Time (min)		Exposure[2][3] (mR)			Notes
	Start	Stop	Persons[1]	Whole Body	Extremities	
Decision to take sample	0	0	N/A	N/A	N/A	Assumes TSC and OSC activated and sample room habitated
Read containment atmosphere H_2 levels in control room	0	5	1	NEG	N/A	
Operate control panel for dilute reactor coolant	0	20	4	9.5	9.5	6" lead shielding
Transport dilute reactor coolant to laboratory	20	42	2	3.6+1	2.5+2	6" lead shielding (Max) 3" lead shielding (Min)
Prepare coolant for isotopic	42	44.5	1	5.0-1	6.3+1	4" lead glass for W.B. (Max) 1/2" lead shielding (Min)
Perform isotopic analysis of coolant	44.5	49.5	1	2.2-4	2.0-1	
Analyze coolant for boron	49.5	54.2	1	2.5	8.6+1	4" lead glass + 2" lead for W.B. 1/2" lead shielding
Prepare sample panel for containment atmosphere	20	20	2	0	0	6" lead shielding
Operate control panel for containment atmosphere	20	35	2	4.8+0	4.8+0	2" lead shielding
Transfer containment atmosphere to small cask	35	39.8	1	1.8+1	2.4+2	2" lead shielding
Transport containment atmosphere to laboratory	39.8	58.5	2	5.8+2	2.4+3	3" lead shielding
Prepare containment atmosphere for isotopic	58.5	63.9	1	3.3	5.2+2	4" lead glass & 2" lead for W.B. (Max) 1/2" lead shielding (Min)
Perform isotopic analysis of containment atmosphere	63.9	68.9	1	2.7-3	2.0-0	
Operate control panel for dissolved gas	39.8	109.8	3	2.5+1	2.5+1	6" lead shielding

TABLE II.B.3-1
(Sheet 2 of 2)

TIME AND DOSE PROJECTIONS FOR PASS SAMPLING, TRANSPORT, AND ANALYSIS

Task	Time (min)		Exposure[2][3] (mR)			Notes
	Start	Stop	Persons[1]	Whole Body	Extremities	
Operate control panel for 10-ml reactor coolant	109.8	119.8	3	3.6+0	3.6+0	6" lead shielding
Transport 10-ml reactor coolant to laboratory	119.8	179.1	3	6.0+1	3.8+3	6" lead shielding (Max) 2" lead shielding (Min)
Analyze 10-ml reactor coolant for chloride	179.1	183.6	1	2.4+2	8.1+3	4" glass lead & 2" lead for W.B. (Max) 1/2" lead shielding (Min)

(1) Number of persons performing particular task.
(2) Doses are based on the assumption that the decision to take a sample is made 1 hr after reactor scram.
(3) The exposure values shown in Table II.B.3-1 are based on a power level of 3,323 MWt. Due to a power increase to 3,467 MWt, the exposure values shown must be multiplied by a factor of 1.0136.

TABLE II.B.3-2

POST-ACCIDENT SAMPLING ANALYTICAL METHODS

Analysis	Method	Suitability	Range	Accuracy
Boron	Carminic acid	GE NEDC-30088 In-house testing	50-1,000 ppm	±50 ppm
Chloride	Specific ion electrode	ASTM D512D In-house testing	1-10 ppm >10 ppm	±1 ppm ±10%
pH	Combination pH electrode	GE NEDC-30088	2-12 pH	±0.2 pH
Isotopic	Gamma spectral analysis	In-house testing	1 µCi/gm-10 Ci/gm	±200%
Total Dissolved Gas[1]	Gas sample pressure measurements	GE testing In-house testing	25-50 cc/kg 50-400 cc/kg	±50% ±30%
Dissolved H_2 or O_2	Gas chromatograph and pressure measurements	GE testing	25-50 cc/kg 50-400 cc/kg	±50% ±30%
Hydrogen[2]	Gas chromatograph	In-house testing	0.1-100%	±0.1%
Oxygen[2]	Gas chromatograph	In-house testing	0.5-100%	±0.5%

(1) Verification is inconclusive.
(2) Backup analysis for on-line H_2/O_2 monitoring system.

II.B.4 TRAINING FOR MITIGATING CORE DAMAGE

FSAR Cross-Reference

Section 13.2

NUREG-0737 Position

Licensees are required to develop a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged. They must then implement the training program.

STAs and operating personnel from the Plant Manager through the operations chain to the licensed Operators shall receive all the training indicated in Enclosure 3 to H. R. Denton's letter dated March 28, 1980.

Managers and Technicians in the Instrumentation and Control (I&C), Health Physics, and Chemistry Departments shall receive training commensurate with their responsibilities.

Nine Mile Point Unit 2 Position

The Unit 2 Operator training program for mitigating core damage is incorporated in the Unit 2 Training Program, as described in Section 13.2.

II.B.8 RULEMAKING DECISION ON DEGRADED CORE ACCIDENTS

FSAR Cross-Reference

Sections 5.4.7, 6.2.5, 6.3, 9.3.1

10CFR50.44 (December 2, 1981)

50.44 Standards for Combustible Gas Control System in Light Water Cooled Power Reactors (c)(1) For each boiling or pressurized light-water nuclear power reactor fueled with oxide pellets within cylindrical zircaloy cladding, it shall be shown that during the time period following a postulated LOCA, but prior to effective operation of the combustible gas control system, either: (i) an uncontrolled hydrogen-oxygen recombination would not take place in the containment; or (ii) the plant could withstand the consequences of uncontrolled hydrogen-oxygen recombination without loss of safety function.

(2) If the conditions set out in paragraph (c)(1) of this section cannot be shown, the containment shall be provided with an inerted or an oxygen-deficient atmosphere in order to provide protection against hydrogen burning and explosions during the time period specified in paragraph (c)(1) of this section.

(3) Notwithstanding paragraphs (c)(1) and (c)(2) of this section: (i) Effective May 4, 1982, or 6 months after initial criticality, whichever is later, an inerted atmosphere shall be provided for each boiling light-water nuclear power reactor with a Mark II-type containment; and

(ii) By the end of the first scheduled outage beginning after July 5, 1982, and of sufficient duration to permit required modifications, each light-water nuclear power reactor that relies upon a purge/repressurization system as the primary means for controlling combustible gases following a LOCA shall be provided with either an internal recombiner or the capability to install an external recombiner following the start of an accident. The internal or external recombiners must meet the combustible gas control requirements in paragraph (d) of this section. The containment penetrations used for external recombiners must either be:

(A) dedicated to that service only, conform to the requirements of Criteria 54 and 56 of Appendix A of this part, be designed against postulated single failures for containment isolation purposes, and be sized to satisfy the flow requirements of the external recombiners, or

(B) of a combined design for use by either external recombiners or purge/repressurization systems and other systems, conform to the requirements of Criteria 54 and 56 of Appendix A of this part, be designed against postulated single failures both for containment isolation purposes and for operation of the external recombiners or purge/repressurization systems, and be sized to satisfy the flow requirements of the external recombiners or purge repressurization systems.

(iii) To provide improved operational capability to maintain adequate core cooling following an accident, by the end of the first scheduled outage beginning after July 1, 1982, and of sufficient duration to permit required modifications, each light-water nuclear power reactor shall be provided with high point vents for the RCS, for the reactor vessel head, and for other systems required to maintain adequate core cooling if the accumulation of noncondensible gases would cause the loss of function of these systems. (High point vents are not required, however, for the tubes in U-tube steam generators.) The high point vents must be remotely operated from the control room. Since these vents form a part of the RCPB, the design of the vents and associated controls, instruments and power sources must conform to the requirements of Appendix A and Appendix B of this part. In particular, the vent system shall be designed to ensure a low probability that (A) the vents will not perform their safety functions and (B) there would be inadvertent or irreversible actuation of a vent. Furthermore, the use of these vents during and following an accident must not aggravate the challenge to the containment or the course of the accident.

Nine Mile Point Unit 2 Position

The Unit 2 plant shall be provided with a non-Category 1 liquefied nitrogen storage and nitrogen gas distribution system for inerting the primary containment atmosphere. The primary containment nitrogen inerting system will control the oxygen concentration at around 4 percent by volume in the inerted condition. The system is set to alarm at 4.5-percent oxygen concentration. The nitrogen system shall also provide instrument gas for actuating all AOVs within the primary containment, including the main steam relief valves and ADS relief valves. The system also includes provisions for actuating these valves with instrument air during periods when the reactor is secured and the primary containment is not in the inerted condition. During these periods, the nitrogen instrument gas supply will be valved out, and the air supply will be manually valved in.

II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

FSAR Cross-Reference

Sections 5.2, 5.4

NUREG-0737 Position

BWR licensees and applicants shall conduct testing to qualify the RCS relief and safety valves under expected operating conditions for design basis transients and accidents.

Nine Mile Point Unit 2 Position

The NRC has identified a total of 20 scenarios that could possibly lead to high-pressure two-phase or liquid flow through the SRV.

The Unit 2 project will provide the following means to resolve the NRC concerns:

1. Redundant Level 8 trip for RCIC (Events 4 and 9)

2. Redundant Level 8 trip for HPCS (Events 5 and 10)

3. Redundant nonsafety Level 8 trip logic for the feedwater pumps.

The tests and analyses described in Reference 1 verify the adequacy of SRV operation and the integrity of the SRV piping under expected liquid discharge conditions, and satisfy all requirements of NUREG-0737, Item II.D.1.

As discussed in Appendix A of Reference 1, for Dikkers valves, there are no material, dimensional or operational differences between the in-plant valves and the tested valves. Since the

valves are identical, the test results for Dikkers valves are applicable to the corresponding in-plant valves.

Reference

1. Analysis of Generic BWR Safety/Relief Valve Operability Test Results, NEDO-24988, Class I, October 1981.

In a letter from D. G. Eisenhut of the NRC to C. V. Mangan of NMPC, dated March 29, 1984, the Equipment Qualification Branch requested that NMPC provide additional information concerning TMI Action Plan II.D.1. Following are the responses to each NRC question:

Question 1(A)

The test program utilized a ramshead discharge pipe configuration. Most plants utilize a tee quencher configuration at the end of the discharge line. Describe the discharge pipe configuration used at your plant and compare the anticipated loads on valve internals in the plant configuration to the measured loads in the test program. Discuss the impact of any differences in loads on valve operability.

Response

Unit 2 utilizes a tee quencher at the end of the main steam SRV discharge line (SRVDL). The test program described in NEDE-24988-P used a ramshead discharge device with test conditions simulating the shutdown cooling mode. The impact of the difference on valve operability is accounted for as follows:

> Valve operability is affected by dynamic loads on valve internals. The dynamic loads are governed by (a) backpressure of the SRV and (b) flow through the SRV. Higher backpressures and flow will produce higher dynamic loads.

(a) In the test program, the SRV inlet pressure was equal to 250 psig. The Unit 2 reactor pressure during shutdown cooling mode is approximately 135 psig. The maximum backpressure of the SRV is approximately 35 percent of the SRV inlet pressure; thus, the test program has qualified the SRV to work with backpressure of about two times that of Unit 2. This provides adequate margin to offset the difference in using a tee quencher.

(b) The test program has qualified the SRV with a ramshead discharge device. The tee quencher allowed less flow (257 lbm/sec) than the ramshead (260 lbm/sec) because it has higher flow resistance. Thus, operability of the SRV for Unit

2 SRVDL with a tee quencher will also be qualified.

NRC Question 1(B)

A description of the plant piping configuration is needed: are there anchor points between the in-plant tee quencher and the SRVs, what are the line lengths, what is the length of the first pipe segment between the SRV and the first elbow, and what is the submergence length? Also in your response to Question No. 1, it is stated that the maximum backpressure is 35 percent of the SRV inlet pressure and that the tee quencher allowed a flow of 257 lbm/sec. Describe how these values were obtained.

Response

Anchor points between the in-plant tee quencher and the SRVs are shown in revised Figures 6A.3-4 and 6A.3-5. The line length, submergence length, and the length of the first pipe segment between the SRV and the first elbow are provided in Table 6A.3-3. The numerical results of the maximum backpressure and flow rate are based on steady state steam blowdown results which are calculated from the SWEC computer program STEHAM (Appendix 3A).

Question 2

The test configuration utilized no spring hangers as pipe supports. Plant-specific configurations do use spring hangers in conjunction with snubber and rigid supports. Describe the SRV supports used at your plant and compare the anticipated loads on valve internals for the plant pipe supports to the measured loads in the test program. Describe the impact of any differences in loads on valve operability.

Response

Fourteen of 18 SRV discharge lines use no spring hangers between the SRV and first full anchor. The remaining four lines use spring hangers solely as deadweight supports and to limit deadweight stresses to less than 1,500 psi. Due to their low stiffness, spring hangers have an insignificant impact on the dynamic properties of the piping system and do not affect the operability of the valves. An adequate number of snubbers and rigid supports are provided to support piping for dynamic loads.

Measured stresses in the SRV discharge piping near the SRV outlet, from NEDE-24988-P, are given in Table 1. Computed stresses in Unit 2 SRV discharge piping near the SRV discharge outlet are given in Table 2. The computed stresses are consistently lower than the measured stresses, which are low. Therefore, it is expected that loads on Unit 2 SRVs will be lower than test loads. Hence, there is no impact on valve operability.

TABLE 1

MEASURED STRESSES FOR STEAM BLOWDOWN
IN SRV DISCHARGE PIPING NEAR SRV OUTLET
DIKKERS 8R10 SRV

Strain Gage*	Stress (psi)**
SG21	200
SG22	1,400
SG23	200
SG24	1,400

NOTES:

* Strain gages SG21 through SG24 are at the same location, but differ in orientation.

** Based on 10-in Sch. 80 (0.593-in thick) pipe.

TABLE 2

COMPUTER STRESSES FOR STEAM BLOWDOWN
IN SRV DISCHARGE PIPING NEAR SRV OUTLET

Valve No. 2MSS*PSV-	Calc. No. AX-	Node	Computed Stress (psi)**
120	2A	205	564
121	2A	310	410
122	2A	410	397
123	2A	510	355
124	2B	204	340
125	2B	304	332
126	2B	404	386
127	2B	504	302
128	2B	604	303
129	2C	204	420
130	2C	304	491
131	2C	404	550
132	2C	504	308
133	2C	604	284
134	2D	212	699
135	2D	330	904
136	2D	577	952***
137	2D	721	903

NOTES:

* SRSS (SRV discharge fluid transient, SRV inertia (max)).
** Based on 10-in Sch. 60 (0.5-in thick) pipe.
*** Maximum computed stress of 952 psi is much lower than the measured stress of 1,400 psi shown in Table 1.

Question 3

Report NEDE-24988-P did not identify any valve functional deficiencies or anomalies encountered during the test program. Describe the impact on valve safety function of any valve functional deficiencies or anomalies encountered during the program.

Response

No functional deficiencies or anomalies of the SRVs were experienced during the testing at Wyle Laboratories in compliance with the alternate shutdown cooling mode requirement. All of the valves subjected to test runs opened and closed without loss of pressure integrity or damage. Anomalies encountered during the test program were all due to failures of test facility instrumentation, equipment, data acquisition system, or deviation from the approved test procedure.

The test specification for each valve required six runs. Under the test procedure, any anomaly caused the test run to be judged invalid. All anomalies were reported in the test report. The Wyle Laboratories test log sheet for the Dikkers valve test is in Table 3.

Each Wyle test report for the respective valves identifies each test run performed, documents whether or not the test run is valid, and states the reason for considering the run invalid. No anomaly encountered during the required test program affects any valve's safety or operability function.

All valid test runs are identified in Table 2.2-1 or NEDE-24988-P. The data presented in Table 4.2-1 for each valve were obtained from the Table 2.2-1 test runs and were based on the following selection criteria:

1. Presenting the maximum representative loading information obtained from the steam run data.

2. Presenting the maximum representative water loading information obtained from the 15°F subcooled water test data.

3. Presenting the data on the only test run performed for the 50°F subcooled water test condition.

TABLE 3

OPERABILITY TEST LOG - SRV DK-1

Test No.	Media	Load Line Configuration	Date	Test Remarks
101	Steam	1	03/03/81	Acceptable
102	Water	1	03/03/81	Acceptable
103	Steam	1	03/03/81	Acceptable
104	Water	1	03/04/81	Acceptable
105	Steam	1	03/04/81	Acceptable
106	Water	1	03/04/81	Acceptable

Question 4

The purpose of the test program was to determine valve performance under conditions anticipated to be encountered in the plants. Describe the events and anticipated conditions at the plant for which the valves are required to operate and compare these plant conditions to the conditions in the test program. Describe the plant features assumed in the event evaluations used to scope the test program and compare them to plant features at your plant. For example, describe high-level trips to prevent water from entering the steam lines under high-pressure operating conditions as assumed in the test event and compare them to trips used at your plant.

Response

The purpose of the test program was to demonstrate that the SRV will open and reclose under all expected flow conditions. The expected valve operating conditions were determined from accidents and anticipated transients referenced in RG 1.70 Revision 2. Additional single failures were considered so that dynamic forces on SRVs would be maximized. By this approach, the BWROG, in the enclosure to the September 17, 1980, letter from D. B. Waters to R. H. Vollmer, identified 13 events which may result in liquid or two-phase SRV inlet flow that would maximize the dynamic forces on the SRV. Among the 13 events, the alternate shutdown cooling mode was found to be the only expected event which will result in liquid flow at the valve inlet. Consequently, this event was simulated in the SRV test program. The conclusion and test results applicable to Unit 2 are discussed subsequently.

The SRV inlet conditions in the test program, as documented in NEDE-24988-P, are 15°F to 50°F subcooled liquid at 20 psig to 250 psig. For Unit 2, the inlet condition during shutdown cooling (Event 7) is approximately 35°F subcooling at a pressure of approximately 135 psig.

The 13 events and the plant-specific features that mitigate these events are summarized in Table 4. Of these 13 events, only 11 are applicable to the Unit 2 design. Two events, namely 3 and 11, are not applicable because Unit 2 does not have a HPCI system. For the 11 remaining events, the Unit 2-specific features, such as trip logic, power supplies, instrument line configuration, alarms, and Operator actions, have been compared to the base plant analysis presented in the BWROG submittal dated September 17, 1980. For these events, Table 4 demonstrates that the Unit 2-specific features are included in the base plant analyses. Furthermore, the time available for Operator action is expected to be longer in the Unit 2 plant than in the base plant analysis for each event where Operator action is required.

As discussed previously, the BWROG evaluated transients, including single active failures, that would maximize the dynamic forces on the SRVs. As a result of this evaluation, the alternate shutdown cooling mode is the only expected event involving liquid or two-phase flow.

Consequently, this event was tested in the BWR SRV test program. The fluid and flow conditions tested in the BWROG test program conservatively envelope the Unit 2 plant-specific fluid conditions expected for the alternate shutdown cooling mode of operation.

TABLE 4
(Sheet 1 of 4)

EVENTS EVALUATED

Plant Features	No. 1 - FW Cont. Failure, FW L8 Trip Failure	No. 2 - Press. Reg. Failure	No. 3 - Trans. HPCI, HPCI L8 Trip Failure	No. 4 - Trans. RCIC, RCIC L8 Trip Failure	No. 5 - Trans. HPCS, HPCS L8 Trip Failure	No. 6 - Trans. RCIC Hd. Spr.	No. 7 - Alt. Shtdwn Cooling, Shtdwn Suction Unavail.	No. 8 - MSL Brk OSC	No. 9 - SBA, RCIC, RCIC L8 Trip Failure	No. 10 - SBA, HPCS, HPCS L8 Trip Failure	No. 11 - SBA, HPCI, HPCI L8 Trip Failure	No. 12 - SBA, Depress. & ECCS Over., Operator Error	No. 13 - LBA, ECCS Overf Brk Isol.
High water Level 7 alarm	X/S		X/NA	X/S	X/S				X/S	X/S	X/NA	X/S	X/S
High drywell pressure alarm													
FW Level 8 trip	X/S	X/S											
RCIC Level 8 trip			X/NA	X/S	X/S				X/S	X/S	X/NA		X/S
HPCS Level 8 trip				X/S	X/S				X/S	X/S			X/S
HPCI Level 8 trip			X/NA	X/NA					X/NA		X/NA		X/NA
HPCI/S and RCIC initiation on low water level	X/S	X/S	X/NA	X/S	X/S	X/S		X/S	X/S				X/S
HPCI/S initiation on high drywell pressure			X/NA	X/NA					X/S	X/S	X/NA	X/S	X/S
RCIC initiation on high drywell pressure													X/NA

TABLE 4
(Sheet 2 of 4)

EVENTS EVALUATED

Plant Features	No. 1 - FW Cont. Failure, FW L8 Trip Failure	No. 2 - Press. Reg. Failure	No. 3 - Trans. HPCI, HPCI L8 Trip Failure	No. 4 - Trans. RCIC, RCIC L8 Trip Failure	No. 5 - Trans. HPCS, HPCS L8 Trip Failure	No. 6 - Trans. RCIC Hd. Spr.	No. 7 - Alt. Shtdwn Cooling, Shtdwn Suction Unavail.	No. 8 - MSL Brk OSC	No. 9 - SBA, RCIC, RCIC L8 Trip Failure	No. 10 - SBA, HPCS, HPCS L8 Trip Failure	No. 11 - SBA, HPCI, HPCI L8 Trip Failure	No. 12 - SBA, Depress. & ECCS Over., Operator Error	No. 13 - LBA, ECCS Overf Brk Isol.
Low-pressure ECCS initiation on high drywell pressure									(2)	(2)	(2)	X/S	X/S
Low-pressure initiation on low water level													X/S
FW Pumps trip on low suction pressure or high vibration	X/S												
HPCS trip on high back-pressure			X/NA								X/NA		
RCIC trip on high back-pressure				X/S					X/S				
Turbine trip on vessel high level	X/S	X/S											
MSIV closure on low turbine inlet pressure	X/S	X/S						X/S					

TABLE 4
(Sheet 3 of 4)

EVENTS EVALUATED

Plant Features	No. 1 - FW Cont. Failure, FW L8 Trip Failure	No. 2 - Press. Reg. Failure	No. 3 - Trans. HPCI, HPCI L8 Trip Failure	No. 4 - Trans. RCIC, RCIC L8 Trip Failure	No. 5 - Trans. HPCS, HPCS L8 Trip Failure	No. 6 - Trans. RCIC Hd. Spr.	No. 7 - Alt. Shtdwn Cooling, Shtdwn Suction Unavail.	No. 8 - MSL Brk OSC	No. 9 - SBA, RCIC, RCIC L8 Trip Failure	No. 10 - SBA, HPCS, HPCS L8 Trip Failure	No. 11 - SBA, HPCI, HPCI L8 Trip Failure	No. 12 - SBA, Depress. & ECCS Over., Operator Error	No. 13 - LBA, ECCS Overf Brk Isol.
MSIV closure on high steam flow		X/S						X/S					
MSIV closure on high steam tunnel temperature								X/S					
MSIV closure on high radiation								X/S					
Reactor scram on turbine trip	X/S	X/NA	(3)										
Reactor scram on neutron flux monitor		X/NA	(3)										
Reactor scram on MSIV closure		X/S											
Reactor scram on high radiation								X/S	(1)				
Reactor scram on high drywell pressure									X/S	X/S	X/NA	X/S	X/S
Reactor scram on low water level													X/S

TABLE 4
(Sheet 4 of 4)

EVENTS EVALUATED

Plant Features	No. 1 - FW Cont. Failure, FW L8 Trip Failure	No. 2 - Press. Reg. Failure	No. 3 - Trans. HPCI, HPCI L8 Trip Failure	No. 4 - Trans. RCIC, RCIC L8 Trip Failure	No. 5 - Trans. HPCS, HPCS L8 Trip Failure	No. 6 - Trans. RCIC Hd. Spr.	No. 7 - Alt. Shtdwn Cooling, Shtdwn Suction Unavail.	No. 8 - MSL Brk OSC	No. 9 - SBA, RCIC, RCIC L8 Trip Failure	No. 10 - SBA, HPCS, HPCS L8 Trip Failure	No. 11 - SBA, HPCI, HPCI L8 Trip Failure	No. 12 - SBA, Depress. & ECCS Over., Operator Error	No. 13 - LBA, ECCS Overf Brk Isol.
Reactor isolation on low water level													X/S

KEY: X = Feature considered in base case analysis.
S = Feature in plant-specific design.
NA = Not applicable.

NOTES: (1) As a consequence of MSIV closure.
(2) High vessel pressure prevents initiation.
(3) Scram bypassed below 30 percent power.

Question 5

The valves are likely to be extensively cycled in a controlled depressurization mode in a plant-specific application. Was this mode simulated in the test program? What is the effect of this valve cycling on valve performance and probability of the valve to fail open or to fail closed?

Response

The BWR SRV operability test program was designed to simulate the alternate shutdown cooling mode, which is the only expected liquid discharge event for Unit 2. The sequence of events leading to the alternate shutdown cooling mode follows.

Following normal reactor shutdown, the RO depressurizes the reactor vessel by opening the turbine bypass valves and removing heat through the main condenser. If the main condenser is unavailable, the Operator could depressurize the reactor vessel by using the SRVs to discharge steam to the suppression pool. If SRV operation is required, the Operator cycles the valves in order to ensure that the cooldown rate is maintained within the Technical Specification limit of 100°F in any 1-hr period. When the vessel is depressurized, the Operator initiates normal shutdown cooling by use of the RHR system. If that system is unavailable because the valve on the RHR shutdown cooling suction line fails to open, the Operator may initiate the alternate shutdown cooling mode.

For alternate shutdown cooling, the Operator opens the SRVs and initiates a RHR pump utilizing the suppression pool as the suction source. The reactor vessel is filled such that water is allowed to flow into the main steam lines, out of the SRV, and back to the suppression pool. Cooling of the system is provided by use of a RHR heat exchanger.

In order to ensure continuous long-term heat removal, the SRV is kept open and no cycling of the valve is performed. To control the reactor vessel cooldown rate, the Operator is instructed to control the flow rate into the vessel. Consequently, no cycling of the SRV is required in the alternate shutdown cooling mode, and no cycling of the SRV was performed in the generic BWR SRV operability test program.

Alternately, when the Operator is using EOPs to control RPV parameters and shutdown cooling is not available, the Operator is permitted to continue cooldown using the systems previously used for depressurization. These systems include SRVs, main steam line drains, RWCU, and RCIC.

The ability of the Unit 2 SRV to withstand extensive cycling for steam discharge conditions has been confirmed during steam discharge qualification testing of the valve by the valve vendor. Based on the SRV qualification testing, cycling of the valves in

a controlled depressurization mode for steam discharge conditions will not affect valve performance adversely. Furthermore, the probability of the valve to fail open or closed is extremely low.

Question 6

Describe how the values of the valve C_v's in report NEDE-24988-P will be used at your plant. Show that the methodology used in the test program to determine the valve C will be consistent with the application at your plant.

Response

The flow coefficient, C_v, for the Dikkers SRV was determined in the generic SRV test program (NEDE-24988-P). The average flow coefficient calculated from test results for the Dikkers valve is reported in Table 5.2-1 of NEDE-24988-P. This test value has been used by Unit 2 to confirm that the liquid discharge flow capacity of the SRVs will be sufficient to remove core decay heat in the alternate shutdown cooling mode. The C_v value determined in the SRV test demonstrates that the SRVs are capable of returning flow to the suppression pool.

If the alternate shutdown cooling mode is required, the Operator is to ensure that adequate core cooling is provided by monitoring the following parameters: RHR flow rate and reactor vessel pressure and temperature.

The flow coefficient for the Dikkers valve reported in NEDE-24988-P was determined from the SRV flow rate when the valve inlet was pressurized to approximately 250 psig. The valve flow rate was measured with the supply line flow venturi upstream of the steam chest. The C_v for the valve was calculated using the nominal measured pressure differential between the valve inlet (steam chest) and 3 ft downstream of the valve and the corresponding measured flow rate. Furthermore, test conditions and configurations were representative of Unit 2 conditions for the alternate shutdown cooling mode, e.g., pressure upstream of the valve, fluid temperature, friction losses, and liquid flow rate. Therefore, the reported C_v values are appropriate for application to Unit 2.

II.D.3 SRV POSITION INDICATION

FSAR Cross-Reference

Sections 5.4, 7.6, 7.3.2

NUREG-0737 Position

The RCS 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.

The basic requirement is to provide the Operator with unambiguous indication of valve position (open or closed) so that appropriate Operator actions can be taken. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication. 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 and action.

The valve position indication should be seismically qualified consistent with the component or system to which it is attached. The position indication should be qualified for its appropriate environment (any transient or accident that would cause the relief or safety valve to lift).

Nine Mile Point Unit 2 Position

Unit 2 has two means of SRV position indication. The primary means is an acoustic monitoring system that monitors SRV tailpipe noise. This system is IE and is qualified for in-containment use. Valve position is indicated in the control room and is entered into the Emergency Response Facility (ERF) computer. The secondary means of valve lift monitoring is non-IE thermocouples on the SRV tailpipe. This monitoring means is only a backup/verification of valve lift and is displayed on a temperature recorder as described in Section 7.3.2.

An array of 10 LEDs per safety valve is provided. The LEDs represent percentage of full valve flow from 0.01 to 1.00. The setpoint is to be determined in the field starting at 0.01 (1-percent flow) and increasing in the lowest increments possible until no spurious alarms are received. This will prevent alarms on valve weepage or background noise.

The output of the acoustic monitoring system drives individual valve open/closed indications on control boards. The system also drives sequence of events (SOE) input computer points. When a valve lifts, the Operator is alerted via the alarm cathode ray tube (CRT) and alarm printer in the main control room.

II.E.4.1 DEDICATED RECOMBINER PENETRATION

FSAR Cross-Reference

Section 6.2.5

NUREG-0737 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 of Appendix A to 10CFR50, 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.

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. The dedicated penetration or the combined single-failure proof alternative shall be sized so that the flow requirements for the use of the recombiner or purge system are satisfied. The design shall be based on 10CFR50.44 requirements. Components furnished to satisfy this requirement shall be safety-grade.

Licensees that rely on purge systems as the primary means for controlling combustible gases following a LOCA, who do not now have recombiners, must have the capacity to install external recombiners. (Installed internal recombiners are an acceptable alternative.) Containment atmosphere dilution (CAD) systems are considered to be purge systems for the purpose of implementing the requirements of this TMI task.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 plant has redundant external recombiners with dedicated containment penetrations. These recombiners meet the single-failure requirements of GDC 54 and 56 of Appendix A to 10CFR50.

II.E.4.2 CONTAINMENT ISOLATION DEPENDABILITY

<u>FSAR Cross-Reference</u>

Sections 6.2.4, 7.3

<u>NUREG-0737 Position</u>

<u>Position 1</u> Containment isolation system designs shall comply with the recommendations of SRP Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation). The reference to SRP 6.2.4 is only to the diversity requirements set forth in that document.

<u>Position 2</u> All plant personnel shall give careful consideration to 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. For post-accident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet the requirements of GDC 54, 55, 56, and 57, as clarified by SRP 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 SRP Section 6.2.4, to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

<u>Position 3</u> All nonessential systems shall be automatically isolated by the containment isolation signal. Revision 2 to RG 1.141 will contain guidance on the classification of essential versus nonessential systems.

<u>Position 4</u> 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. Administrative provisions to close all isolation valves manually before resetting the isolation signals is not an acceptable method for meeting the requirements.

<u>Position 5</u> The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions. 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.

<u>Position 6</u> Containment purge valves that do not satisfy the operability criteria set forth in BTP 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. 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 should use pressure history data from similar plants that have operated more than 1 yr, if possible, to arrive at a minimum containment setpoint pressure.

Position 7 Containment purge and vent isolation valves must close on a high radiation signal. 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 hr that the purge valves are closed.

Nine Mile Point Unit 2 Position

Unit 2 was reviewed for compliance of containment isolation dependability.

A Containment Isolation Dependability Study - Report of Findings was generated to address all NRC concerns as defined in NUREG-0737, Task II.E.4.2. The results of the study are contained in Attachment 1.10-1.

The following systems were reviewed and found to comply with all of the applicable NRC positions of NUREG-0737, Item II.E.4.2.

Fire Protection Water

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Reactor Building Floor Drains

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Containment Leakage Monitoring

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

DBA Hydrogen Recombiner

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Reactor Building Equipment Drains

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Feedwater

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	N/A	Yes	Yes	Yes	N/A	N/A	N/A

Reactor Building Closed Loop Cooling Water

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Reactor Core Isolation Cooling

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Instrument Air

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Low-Pressure Core Spray

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	N/A	Yes	N/A	N/A	N/A	N/A	N/A

High-Pressure Core Spray

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	N/A	N/A

Reactor Containment Inerting and Purge

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	Yes	N/A	Yes	Yes

(1) Position 1 requires diverse parameters for the initiation of containment isolation. Diverse parameters are sensed in order to detect a LOCA and other DBAs. The preferred diverse isolation signals are low reactor vessel water level or high drywell pressure.

(2) Position 2 establishes a requirement to define essential and nonessential systems and to classify in accordance with these definitions all systems that contain piping that penetrate the containment as either essential or nonessential.

(3) Position 3 requires all nonessential systems to be automatically isolated by the containment isolation signal.

(4) Position 4 requires automatic containment isolation valves to remain closed after the isolation is reset. Deliberate Operator action is required to reopen a containment isolation valve after the isolation is reset. Gang reopening is not acceptable following reset of containment isolation signal or a single Operator action.

(5) Position 5 requires the reduction of the high drywell pressure trip point setting, used for containment isolation, to the minimum compatible with normal operating conditions.

(6) Position 6 requires containment purge supply or exhaust lines that do not satisfy the operability criteria set forth in either BTP CSB 6-4 or the Staff Interim Position of October 23, 1979, to be sealed closed as defined in SRP 6.2.4, Item II.6.f, during operational modes of power operation, startup, hot standby, and hot shutdown.

(7) Position 7 requires all containment purge supply and exhaust isolation valves to close on a high radiation signal.

ATTACHMENT 1.10-1
(Sheet 1 of 9)

CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

All systems and system lines that contain piping that penetrates the containment are identified and classified as either essential or nonessential in Table II.E.4.2-1.

The following summaries contain detailed findings and recommendations for those systems in which less than full compliance with applicable NRC positions were found to exist.

Main Steam Lines and Main Steam Drain Lines

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	Yes	N/A	N/A	N/A

NRC Position 1

Finding: The containment isolation valves in nonessential lines listed below do not receive the preferred diverse containment isolation signal, i.e., high drywell pressure.

Penetration	Title	Valve No.
Z1A	Main Steam Line A	2MSS*AOV6A
	Main Steam Line A	2MSS*AOV7A
	Main Steam Line A Drain Line	2MSS*MOV208
Z1B	Main Steam Line B	2MSS*AOV6B
	Main Steam Line B	2MSS*AOV7B
	Main Steam Line A Drain Line	2MSS*MOV208
Z1C	Main Steam Line C	2MSS*AOV6C
	Main Steam Line C	2MSS*AOV7C
	Main Steam Line A Drain Line	2MSS*MOV208
Z1D	Main Steam Line D	2MSS*AOV6D
	Main Steam Line D	2MSS*AOV7D
	Main Steam Line A Drain Line	2MSS*MOV208
Z2	Main Steam Line Inboard Drain Valve	2MSS*MOV111
	Main Steam Line Outboard Drain Valve	2MSS*MOV112

ATTACHMENT 1.10-1
(Sheet 2 of 9)

CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE WITH NUREG-0737 (TASK II.E.4.2)

Justification: These lines provide a heat sink path for the RPV. It is desirable to keep the MSIVs open for this function during postulated small leaks or breaks. Therefore, high drywell pressure has been deliberately omitted from isolation of main steam and main steam drain lines.

These lines also isolate on the following accident isolation signals:

Signal Code	Description
X	Low reactor vessel water level 1
C	High radiation - main steam line
D	High main steam line flow
E	High main steam line tunnel area ambient temperature
P	Low main steam line pressure turbine inlet
R	Low main condenser vacuum
T	High main steam line tunnel area differential temperatures
RM	Remote manual switch from control room

Action: No changes are required.

NRC Positions 1 and 3

Finding: Remote manually air-operated containment isolation valves in nonessential penetrations listed below do not receive the preferred diverse containment isolation signal, i.e., reactor water low level and/or high drywell pressure.

Penetration	Title	Valve No.
Z1A	MSIV Line A Drain Valve	2MSS*AOV97A
Z1B	MSIV Line B Drain Valve	2MSS*AOV97B
Z1C	MSIV Line C Drain Valve	2MSS*AOV97C
Z1D	MSIV Line D Drain Valve	2MSS*AOV97D

Justification: These valves are not required for containment isolation. Isolation outside the containment is provided by 2MSS*MOV208 and hence containment integrity is maintained. Therefore, reactor water level low and/or high drywell pressure has been omitted from these MSIV line drain valves.

Action: No changes are required.

ATTACHMENT 1.10-1
(Sheet 3 of 9)

CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE WITH NUREG-0737 (TASK II.E.4.2)

Service Air

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	N/A	N/A	N/A	N/A

NRC Positions 1 and 3

Finding: Manually-operated containment isolation valves in the nonessential penetrations listed below are closed during the normal and post-DBA conditions.

Penetration	Title	Valve No.
Z36	Service Air to Drywell	2SAS*HCV161 2SAS*HCV163
Z44E	Service Air to Drywell	2SAS*HCV160 2SAS*HCV162

Action: Administrative controls will be provided, encompassing requirements of SRP 6.2.4 (Section II.6.f), RG 1.141, and ANSI N271-1976.

Breathing Air

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	N/A	N/A	N/A	N/A

NRC Positions 1 and 3

Finding: Manually-operated containment isolation valves in the nonessential penetrations listed below are normally closed.

Penetration	Title	Valve No.
Z37	Breathing Air to Drywell	2AAS*HCV134 2AAS*HCV136
Z44F	Breathing Air to Drywell	2AAS*HCV135 2AAS*HCV137

Action: Administrative controls will be provided encompassing requirements of SRP 6.2.4 (Section II.6.f), RG 1.141, and ANSI N271-1976.

ATTACHMENT 1.10-1
(Sheet 4 of 9)

CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

Standby Liquid Control

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	N/A	N/A	N/A	N/A

NRC Positions 1 and 3

Finding: Isolation of the SLCS injection is provided by two outboard motor-operated stop check valves and a nonmotorized inboard check valve.

Justification: Check valves are used for isolation in this instance so that standby liquid control (SLC) injection will be possible even if the reactor is isolated because of an accident. Check valves are considered an adequate isolation means and no other isolation is required besides the check valves and the normally closed explosive valves upstream of the check valves. It is recognized that the check valve isolation scheme does not meet the present criteria specified in 10CFR50, Criterion 55. It is our position that the inboard and outboard check valves, along with the protection supplied by the normally closed explosive valves, provide adequate containment isolation.

Action: No changes are required.

Control Rod Drive

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	N/A	N/A	N/A	N/A

NRC Positions 1 and 3

Finding: The CRD insert and withdraw lines are not designed to isolate after a LOCA.

Justification: The CRD insert and withdraw lines are not part of the reactor coolant pressure since they do not directly communicate with the reactor coolant. The classification of these lines is quality group B and they are, therefore, designed in accordance with ASME Section III, Code Class 2. The basis to which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

In the design of the CRD system, it has been accepted practice to minimize the number of valves for isolation purposes as this introduces possible failure mechanisms into the shutdown (scram)

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CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

function. The CRD insert and withdraw lines can be isolated by the solenoid valves outside the primary containment. These lines are small and terminate in a system that is designed to prevent leakage. Solenoid valves normally are closed, but open on rod movement and during reactor scram. In addition, a ball check valve located in the CRD flange housing automatically seals the insert line in the event of a break. Primary containment pressurization will not result from a line break in the primary containment, since these lines contain small volumes at low energy levels.

Action: No changes are required.

Traverse In-Core Probe

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	N/A	N/A	N/A	N/A

NRC Positions 1 and 3

Finding: The TIP drive line isolation valves and purge valves are not provided with diverse, automatic isolation signals.

Justification: Since the TIP lines are considered instrument lines, 10CFR50 GDC 56 is met in accordance with RG 1.11 requirements. The TIPs are normally withdrawn and the ball valves closed. If an event occurs while the TIP is inserted into the core and the TIP should fail to retract, the shear valve can be operated manually to provide the necessary containment isolation.

Action: No changes are required.

Containment Atmospheric Monitoring

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	Yes	Yes	Yes	No	N/A	N/A	N/A

NRC Position 1

Finding: Both inboard and outboard containment isolation valves in each essential line receive diverse containment isolation signals, but these signals are from the same ESF division.

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CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

Penetration	Title	Valve No.
Z60B	Drywell Isolation Valve	2CMS*SOV24A 2CMS*SOV24C
Z60D	Drywell Isolation Valve	2CMS*SOV33A 2CMS*SOV32A
Z60F	Drywell Isolation Valve	2CMS*SOV24B 2CMS*SOV24D
Z60H	Drywell Isolation Valve	2CMS*SOV32B 2CMS*SOV33B
Z61B	Suppression Chamber Isolation Valve	2CMS*SOV26A 2CMS*SOV26C
Z61C	Suppression Chamber Isolation Valve	2CMS*SOV34A 2CMS*SOV35A
Z61E	Suppression Chamber Isolation Valve	2CMS*SOV26D 2CMS*SOV26B
Z61F	Suppression Chamber Isolation Valve	2CMS*SOV35B 2CMS*SOV34B

Justification: The valves are used for the hydrogen and oxygen monitoring function of containment atmospheric monitoring system, required for post-accident operation, and are composed of two independently-closed loops outside containment. Each closed loop system outside containment satisfies the requirements of SRP 6.2.4, Section II.6.e.

Action: None.

NRC Position 4

Finding: Solenoid-operated containment isolation valves in nonessential penetrations listed below have manual override switches for reopening after a LOCA.

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CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

Penetration	Title	Valve No.
Z60A	Drywell Radiation Monitor Line	2CMS*SOV60A 2CMS*SOV61A
Z60C	Drywell Radiation Monitor Line	2CMS*SOV62A 2CMS*SOV63A
Z60E	Drywell Radiation Monitor Line	2CMS*SOV60B 2CMS*SOV61B
Z60G	Drywell Radiation Monitor Line	2CMS*SOV62B 2CMS*SOV63B

Justification: The keylocks on the switches provide sufficient administrative control of the reopening of the valves following a LOCA. The valves will automatically close on receipt of a LOCA signal. Two deliberate actions are required to reopen each valve.

Action: None.

Reactor Recirculation

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	No	No	N/A	N/A	N/A

NRC Positions 1, 3 and 4

Finding: Isolation of the reactor recirculation pumps A and B seal purge lines in essential penetrations is provided by three simple check valves only.

Penetration	Title	Valve No.
Z38A	Reactor Recirculation Pump A Seal Purge	2RCS*V60A 2RCS*V90A 2RCS*V59A
Z38B	Reactor Recirculation Pump B Seal Purge	2RCS*V60B 2RCS*V90B 2RCS*V59B

Justification: Operation of the recirculation pump seal purge line is desirable during pump operation, and whenever the reactor coolant temperature >200°F, regardless of whether or not the pump is running, including during containment isolation. Automatic

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(Sheet 8 of 9)

CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE
WITH NUREG-0737 (TASK II.E.4.2)

isolation valves are therefore undesirable. Instead, three check valves in series are used, one inside and two outside the containment to provide isolation, thereby enhancing the operational reliability of the seal purge function.

Action: None.

NRC Position 1

Finding: The automatic isolation valves in the nonessential penetration listed below do not receive preferred diverse isolation signal high drywell pressure.

Penetration	Title	Valve No.
Z41	Reactor Water Sample	2RCS*SOV104 2RCS*SOV105

Justification: Operating experience has shown that under some conditions, it is difficult to clear the automatic isolation signals from the reactor water sample line to allow the necessary reactor water samples to be taken. To minimize this inconvenience while maintaining safety standards, all reactor water sample line isolation signals except low reactor water level and high main steam line radiation have been removed.

Action: None.

Reactor Water Cleanup

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	Yes	Yes	N/A	N/A	N/A

NRC Position 1

Finding: High drywell pressure (Signal F) is not an isolation signal for the following valves:

Penetration	Title	Valve No.
Z23	RWCU Pumps Suction from Reactor Coolant	2WCS*MOV102 2WCS*MOV112

Justification: The system is not isolated on high drywell pressure in order to keep the capability of continuously cleaning the reactor vessel coolant during postulated small breaks and leaks.

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CONTAINMENT ISOLATION DEPENDABILITY STUDY COMPLIANCE WITH NUREG-0737 (TASK II.E.4.2)

The system incorporates break-detection logic in conjunction with leak detection systems that will automatically isolate on an unbalanced flow or high temperature.

Action: No changes are required.

Residual Heat Removal

NRC Position	1	2	3	4	5	6	7
Unit 2 Compliance	No	Yes	Yes	Yes	N/A	N/A	N/A

NRC Position 1

Finding: The RHR automatic isolation valves in the nonessential lines listed below do not receive the high drywell pressure signal.

Penetration	Title	Valve No.
Z10A	RHR Shutdown Cooling Return	2RHS*MOV67A 2RHS*MOV40A
Z10B	RHR Shutdown Cooling Return	2RHS*MOV67B 2RHS*MOV40B
Z11	RHR Shutdown Cooling Suction	2RHS*MOV113 2RHS*MOV112

Justification: High drywell pressure (Signal F) has been deliberately omitted from the isolation initiation logic for these line valves to avoid the loss of the RHR shutdown cooling mode for small breaks or leaks.

Action: No changes are required.

TABLE II.E.4.2-1
(Sheet 1 of 2)

ESSENTIAL/NONESSENTIAL SYSTEMS

System	Classification	Basis for Essentiality
1. Main Steam	Nonessential	Not required for safe shutdown.
2. Feedwater	Nonessential	Not required for safe shutdown. Class 1 portion of feedwater line essential. It is desirable to maintain all sources of cooling supply, if available.
3. Reactor Coolant Recirculation	Nonessential	Not required for safe shutdown.
	Essential	Pump seal purge line is required for seal operation.
4. Instrument Air	Nonessential	Not required in short term for safe shutdown.
	Essential	System required in long term to support LPCI and LPCS by recharging ADS accumulators from tanks outside containment.
5. Service Air	Nonessential	Not required for safe shutdown.
6. Breathing Air	Nonessential	Not required for safe shutdown.
7. Standby Liquid Control	Essential	System should be available as backup to the CRD system.
8. RHR		
a. LPCI Mode	Essential	Safety function.
b. Suppression Pool Cooling Mode	Essential	Necessary to control suppression pool temperature.
c. Containment Spray Cooling Mode	Essential	Necessary to control drywell/containment pressure.
d. Shutdown Cooling Mode	Nonessential	Not required for safe shutdown.
9. Reactor Water Cleanup	Nonessential	Not required during or immediately following an accident.
10. Reactor Core Isolation Cooling	Essential	System is used as a backup to HPCS when the reactor becomes isolated from main condenser.
11. Low-Pressure Core Spray	Essential	Safety system.
12. High-Pressure Core Spray	Essential	Safety system.

TABLE II.E.4.2-1
(Sheet 2 of 2)

ESSENTIAL/NONESSENTIAL SYSTEMS

System	Classification	Basis for Essentiality
13. Reactor Building Equipment Drains	Nonessential	Not required for safe shutdown.
14. Containment Leakage Monitoring	Nonessential	Not required for safe shutdown.
15. Reactor Building Closed Loop Cooling Water	Nonessential	Not required for safe shutdown.
16. Reactor Containment Inerting and Purge	Nonessential	Not required for safe shutdown. However, system is used if available as backup to Category I DBA hydrogen recombiner.
17. Containment Atmospheric Monitoring	Essential	System is required for post-accident monitoring of containment pressure, hydrogen, temperature, and level. Radiation monitors are nonessential because they are not required for safe shutdown.
18. DBA Hydrogen Recombiner	Essential	System is required for safe shutdown. Following a LOCA, system is used to remove excess hydrogen that would react with oxygen and lead to high temperature and overpressurization that would result in loss of containment integrity.
19. Fire Protection Water	Nonessential	Not required for safe shutdown.
20. Reactor Building Floor Drains	Nonessential	Not required for safe shutdown.
21. Control Rod Drive	Essential	Required for safe shutdown.
22. Traversing In-core Probe (TIP)	Nonessential	Not required for safe shutdown.

II.F.1 ADDITIONAL ACCIDENT MONITORING INSTRUMENTS

FSAR Cross-Reference

Sections 6.2.1, 6.2.5, 7.5, 11.5, 12.1, 12.3

NUREG-0737 Position

Item II.F.1 of NUREG-0660 contains the following subparts:

1. Noble gas effluent radiological monitor.

2. Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities (this requirement was inadvertently omitted from NUREG-0660; see Task II.F.1.2 for position).

3. Containment high-range radiation monitor.

4. Containment pressure monitor.

5. Containment water level monitor.

6. Containment hydrogen concentration monitor.

NUREG-0578 provides the basic requirements associated with Items 1 through 3 above. Letters issued to all operating nuclear power plants dated September 13, 1979, and October 30, 1979, provided clarification of staff requirements associated with Items 1 through 6 above. II.F.1.1 through II.F.1.6 present the NRC position on these matters.

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 establishment of alarms.

II.F.1.1 Noble Gas Effluent Monitors 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 uCi/cc (Xe-133) are considered 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 ALARA concentrations to a maximum of 10^5 uCi/cc (Xe-133). Multiple monitors are considered necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of ten.

Licensees shall provide continuous monitoring of high-level, post-accident releases of radioactive noble gases from the plant. Gaseous effluent monitors shall meet the requirements specified in Table II.F.1-1. Typical plant effluent pathways to be monitored are also given in the table.

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.

Off-line monitors are not required for the PWR 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.

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:

1. System description, including:

   a. Instrumentation to be used, including range or sensitivity, energy dependence or response, calibration frequency and technique, and vendor's model number, if applicable.

   b. Monitoring locations (or points of sampling), including description of methods used to assure representative measurements and background correction.

   c. Location of instrument readout(s) and method of recording, including description of the method or procedure for transmitting or disseminating the data.

d. Assurance of the capability to obtain readings at least every 15 min during and following an accident.

e. Source of power to be used.

2. 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.

<u>II.F.1.2 Sampling and Analysis of Plant Effluents</u> 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.

Licensees shall provide continuous sampling of plant gaseous effluent for post-accident releases of radioactive iodines and particulates to meet the requirements of Table II.F.1-2. Licensees 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 on-line 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.

The shielding design basis is given in Table II.F.1-2. 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 criteria of GDC 19 of 5 Rem whole-body exposure and 75 Rem to the extremities during the duration of the accident.

The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities that are approximately isokinetic (same velocity) with expected in-duct or in-stack 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 that 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 nonisokinetic sampling conditions, as provided in

Appendix C of ANSI 13.1-1969, may be considered on an ad hoc basis.

Effluent streams that 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.

II.F.1.3 Containment High-Range Radiation Monitor
In-containment radiation level monitors with a maximum range of 10^8 R/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.

Provide two radiation monitor systems in containment that are documented to meet the requirements of Table II.F.1-3.

The specification of 10^8 R/hr in the above position was based on a calculation of post-accident containment radiation levels that included both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA 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.

The monitors shall be located in containment(s) so 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 that 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. For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

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.1-3. Monitors that use thick shielding to increase the upper range will underestimate post-accident radiation levels in the containment by several orders of magnitude because of their insensitivity to low-energy gammas, and are not acceptable.

II.F.1.4 Containment Pressure Monitor 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.

Design and qualification criteria are outlined in 10CFR50 Appendix A.

Measurement and indication capability shall extend to 5 psia for subatmospheric containments.

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.

Continuous display and recording of the containment pressure over the specified range in the control room is required.

The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

<u>II.F.1.5 Containment Water Level Monitor</u> 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 PWRs and cover the range from the bottom to the top of the containment sump. A wide-range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000-gal capacity. For BWRs, a wide-range instrument shall be provided and cover the range from the bottom to 5 ft above the normal water level of the suppression pool.

The containment wide-range water level indication channels shall meet the design and qualification criteria as outlined in 10CFR50 Appendix A. The narrow-range channel shall meet the requirements of RG 1.89.

The measurement capability of 600,000 gal 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 plants.

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.

For BWR pressure-suppression containments, the 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.

The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

II.F.1.6 Containment Hydrogen Monitor 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. Design and qualification criteria are outlined in 10CFR50 Appendix A.

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 min of the initiation of safety injection.

The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.

Nine Mile Point Unit 2 Position

Human Factor Analysis

For a human factor analysis of the displays and controls of the main control room, refer to Task I.D.1 of this section.

II.F.1.1 Noble Gas Effluent Radiological Monitor Unit 2 has two effluent gaseous release paths: the main stack and the reactor building/radwaste building vent. The main stack receives input from SGT, turbine building ventilation, turbine generator gland seal exhaust, offgas, and mechanical vacuum pump exhaust. The reactor building/radwaste building vent receives input from radwaste building ventilation and normal reactor building ventilation (above and below the refueling floor). Each exhaust path is monitored by an off-line gaseous, particulate, and iodine isotopic radiological monitor, equipped with a high-purity germanium detector. The monitor meets all requirements of NUREG-0737 with a range that meets RG 1.97. Calibration of these monitors is performed using calibration sources which are traceable to the National Institute of Standards and Technology (NIST). In order to determine the particulate and iodine detector efficiencies, sources whose spectrum is distributed over the energy band are used. These sources yield the detector efficiencies directly. In the case of the gas detector, numerous spectra are measured with calibrated point sources at precisely-located positions. Absolute detection efficiencies are obtained at 11 gamma-ray energies for each position. Calculations are then employed to obtain the average efficiencies. These values are subsequently verified using a gas sample of known isotopic content.

The efficiency data determined for the particulate iodine and gas channels are entered manually in the system's computer, which determines detector efficiency curves for each station. Those curves cover the range of energies expected from the emissions of radionuclides collected and analyzed at each channel. Through

the use of a multichannel analyzer in conjunction with each detector, the system is capable of identifying a specific isotope and the amount of that isotope present in a sample containing different radionuclides by collecting data at various discrete energy levels. A detailed description of calibration procedures for these monitors can be found in the Unit 2 operations and maintenance manuals. The monitor is capable of functioning both during and following an accident and provides continuous monitoring of high-level post-accident releases of radioactive noble gases from the plant. See Section 11.5.2.1.1 for further information on these monitors.

<u>II.F.1.2 Sampling and Analysis of Plant Effluents</u> The on-line gaseous, particulate, and iodine isotopic radiological monitor provides continuous sampling of plant gaseous effluent for post-accident releases of radioactive iodines and particulates. The monitor provides the capability for sampling and analysis of effluent without personnel interface. If required for supplemental analysis, or if the isotopic monitor is out of service, the present onsite lab at Unit 1 will have the necessary capability to provide for appropriate facilities.

<u>II.F.1.3 Containment High-Range Radiation Monitor</u> Unit 2 has four high-range in-containment radiation monitors. The range meets the requirements of RG 1.97. The monitors are located 90 deg apart on el 261 ft. These monitors are Category I and are powered via divisional instrument buses. Monitor readouts are displayed continuously and recorded in the main control room.

<u>II.F.1.4 Containment Pressure Monitor</u> Unit 2 instrumentation is provided to monitor containment (drywell) pressure over the range 0-150 psig in accordance with RG 1.97. These instruments are Category I and powered via divisional instrument buses. The pressure is continuously displayed and recorded in the main control room.

<u>II.F.1.5 Containment Water Level Monitor</u> Unit 2 instrumentation is provided to monitor the suppression pool water level from the bottom of the ECCS suction line to 17 ft above normal water level. This range is in accordance with RG 1.97. These instruments are Category 1 and are powered via divisional electrical buses. The containment water level is indicated continuously in the main control room.

<u>II.F.1.6 Containment Hydrogen Concentration Monitor</u> The hydrogen monitors can be operated continuously, or be maintained in a standby condition during normal operation. From the standby mode, continuous indication and recording is available in the control room within 90 min after ECCS initiation. An automatic calibration sequence is initiated every 30 days during post-accident operation to maintain the accuracy of the analyzers. Sample trees inside the primary containment provide for representative samples. This system consists of two Category I systems. The range of the monitor is 0 to 30 percent in

accordance with RG 1.97. These instruments are powered via divisional instrument buses.

II.F.2 INADEQUATE CORE COOLING

FSAR Cross-Reference

Section 4.4

NUREG-0737 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.

Previous guidance on the design and qualification criteria for upgrading of existing instrumentation was based on RG 1.97, which is still being developed. Detailed design requirements for in-core thermocouples and additional instrumentation were not specified. The pertinent portions of draft RG 1.97 have now been included as Appendix A. Design requirements for in-core thermocouples used in the ICC monitoring system are specified in Attachment 1. The only significant change in design requirements involves a relaxation of qualification requirements for display systems amenable to computer processing. This facilitates procurement of computer systems and makes feasible the use of CRT displays that may be needed for proper interpretation of some reactor-water-level systems under development. This relaxation can be accomplished without compromise of ICC monitoring reliability by requiring 99-percent availability for the display systems, by requiring post-accident maintenance accessibility for nonredundant portions of the system, and by relying on diverse methods of ICC monitoring that include completely qualified display systems.

Design of new instrumentation should provide an unambiguous indication of ICC. This may require new measurements or a synthesis of existing measurements that meet design criteria (Item 7). The evaluation is to include reactor water level indication.

Licensees and applicants are required to provide the necessary design analysis to support the proposed final instrumentation system for ICC and to evaluate the merits of various instruments to monitor water level and to monitor other parameters indicative of core cooling conditions.

The indication of ICC must be unambiguous in that it should have the following properties:

1. It must indicate the existence of ICC caused by various phenomena (i.e., high-void fraction-pumped flow as well as stagnant boiloff).

2. It must not erroneously indicate ICC because of the presence of an unrelated phenomenon.

The indication must give advance warning of the approach of ICC.

The indication must cover the full range from normal operation to complete core uncovery. 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 in-core 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 uncovery. 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.

All instrumentation in the final ICC system must be evaluated for conformance to Appendix A, as clarified or modified by the provisions of Items 8 and 9 that follow. This is a new requirement.

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 criterion of Item 2, Appendix A, 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 A, Item 5, need not apply to this portion of the instrumentation system. This is a new requirement.

In-core thermocouples located at the core exit or at discrete axial levels of the ICC monitoring system that are part of the monitoring system should be evaluated for conformity with Attachment 1, Design and Qualification Criteria for PWR In-core Thermocouples, which is a new requirement.

The types and locations of displays and alarms should be determined by performing a human factors analysis taking into consideration:

1. 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.

Nine Mile Point Unit 2 Position

The BWROG has concluded that no additional instrumentation is required to monitor ICC. Unit 2 endorses this position. The present water level instrumentation, described in the response to Task II.K.3.27, is fully adequate for predicting the approach to ICC and in allowing the plant Operator to respond properly under all postulated reactor conditions. To reduce vulnerability to failures or malfunctions, analog level transmitters are used to detect water level. This has been evaluated and documented in the GE Report NEDO-24708, entitled, Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors.

In addition, EOPs based upon BWROG EPGs enable the Operator to recognize the approach to ICC. These procedures are in place at Unit 2.

The above procedures and analysis satisfy the requirements of this NRC position relative to ICC.

An evaluation of the effects of high temperatures on reference legs of water level measuring instruments subsequent to high-energy line breaks (HELB) has been made. This includes the potential for reference leg flashing/boiloff, the indication/annunciation available to alert the Control Room Operator of erroneously high vessel level indications resulting from high temperatures, and the effects on safety systems actuation (e.g., delays).

High drywell temperature does not significantly affect measured reactor water level when reactor pressure is greater than the saturation pressure of water in the water level sensing lines because the vertical drop of the wide range, narrow range, and fuel zone range, reference, and variable leg sensing lines in the drywell are approximately equal. The water level indication is not affected because the comparable vertical drops of the reference and variable leg sensing lines in the drywell result in nearly equal changes in hydrostatic pressure in these lines due to reduced water density at increased drywell temperature.

If reactor pressure decreases to less than the saturation pressure of the water in the water level sensing lines, the water in the lines will flash and boil. The flashing and boiling may

result in loss of some of the water in the sensing lines. Loss of water from the sensing lines results in reactor water level measurement error until Operator action refills the sensing lines.

Analyses have demonstrated that water-level-activated safety trips will be initiated for HELBs before reactor pressure decreases to less than the saturation pressure of the water in the sensing lines. Therefore, these safety trips will be initiated before high drywell temperature significantly affects water level measurement.

The Unit 2 containment monitoring design consists of 18 redundant Class 1E temperature elements distributed throughout the primary containment. The containment temperature monitoring system constantly scans and selects the highest containment temperatures for control room indication and annunciation. The control room indication of containment temperatures includes metered indication as well as temperature recorders. The control room annunciation alerts the Operator of high containment temperatures which could lead to possible erroneous level indication.

Long-term (i.e., following RPV blowdown and reflooding) water level measurement errors due to flashing and boiling of water in the sensing lines are postulated to occur as a result of multiple failures by the Operator to follow established emergency procedures. The BWROG has established the position with the NRC that potentially large water level measurement errors resulting from high drywell temperature increase the probability of core melt and these errors should be minimized and/or eliminated. This position was established with the NRC via BWROG Reports #SLI-8211, entitled, Review of BWR Reactor Water Level Measurement System, and #SLI-8218, entitled, Inadequate Core Cooling Detection in BWRs, prepared by S. Levy, Inc.

This response provides the results of an evaluation of the Unit 2 reactor water level sensing line arrangement in the drywell based upon the criterion established by NRC Generic Letter No. 84-23 dated October 26, 1984. Specifically, the acceptance criterion states that:

> "Maximum drop would allow an indicated level at the bottom of the normal operating range when actual level is just above the lower tap for the worst flashing condition..."

It should be noted that the stated criterion is based on the assumption of multiple failures. Under the highly unlikely scenario postulated it is assumed that the Operator:

1. Fails to properly monitor reactor water level (i.e., the most important post-LOCA parameter).

2. Stops all systems providing reactor core inventory makeup.

3. Fails to properly monitor drywell temperature and vessel pressure and reflood the reactor in order to recover/restore water level indication, as required by the emergency procedures, when drywell temperature near the instrument lines exceeds that saturation temperature of the reactor vessel.

4. Fails to initiate the drywell spray at the high drywell temperature specified in the emergency procedures.

The evaluation assumes loss of all water in the part of the reference leg sensing line located in the drywell as a result of failure of the Operators to follow established emergency procedures. The loss of water from the reference leg is assumed to occur due to high drywell temperature conditions (i.e., flashoff that occurs when the reactor is depressurized and long-term boiloff of water due to drywell temperatures higher than reactor temperatures). The error resulting from flashoff and boiloff is proportional to the vertical elevation change of the reference leg in the drywell. Unit 2 has a maximum of 6 ft 11 in vertical elevation of reference legs in the drywell.

This evaluation has shown that for the worst-case flashing condition, the actual water level would be 6.74 ft above the lower tap (or 6.40 ft above the top of the active fuel [TAF]) when the indicated water level is at low water level 4.

Refer to the response for Task II.F.1 for a discussion of in-core thermocouples and to the response for Task I.D.1 for consideration of human factors in the design and layout of the control room.

II.K.1.5 REVIEW OF ESF VALVES

<u>FSAR Cross-Reference</u>

Section 6.3

<u>NUREG-0737 Position</u>[1]

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 ESFs. 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 all operational modes.

<u>Nine Mile Point Unit 2 Position</u>

Each system requiring alignment of valves will have a valve lineup provided as a portion of the operating procedures. System test procedures will require performance of a post-test valve lineup to assure restoration to an operable condition. Valve lineups will require double verification and signoff by independent Operators. These valve lineups will be verified along with system operation as part of the preoperational test program. This will preclude valves being in a wrong position. Additionally, valve lineups and/or operability checks will be reviewed as part of the checkout of maintenance, surveillance, operations, test, or inspection procedures during the preoperational test phase.

II.K.1.10 OPERABILITY STATUS

FSAR Cross-Reference

Section 6.3

NUREG-0737 Position[9]

Review and modify as necessary your maintenance and test procedures to ensure that they require:

a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

Nine Mile Point Unit 2 Position

Unit 2 will review all maintenance and test procedures during the preoperational test phase and ensure that they require verification of operability of redundant safety-related systems, as required by Technical Specifications, prior to the removal of the safety system from service. Explicit notification to and authorization by the SSS of work on a safety-related system shall be verified as being performed prior to removal of a system from service and prior to its return to service. Verification of the operability of safety-related systems following maintenance or test will be performed as part of the test and restoration of a system to service.

[9] Text of NUREG position can be found in Bulletin 79-08.

II.K.1.23 REACTOR VESSEL LEVEL INDICATION

FSAR Cross-Reference

Sections 7.3, 7.5

NUREG-0737 Position[10]

For all BWR facilities with an operating license, complete the following action:

Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of TMI to 3/28/79 accident including Enclosure 1 to IE Bulletin 79-05A.

Nine Mile Point Unit 2 Position

This review has been completed. The actions resulting from TMI that relate to design changes and/or procedural actions are as follows:

Question 1a

This review should be directed toward understanding: 1) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at TMI Unit 2 plant and other actions taken during the early phases of the accident, 2) the apparent operational errors which led to the eventual core damage, and 3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

Response

Unit 2 has reviewed the TMI event with an understanding directed toward the three actions described in Question 1a. The development of EOPs based upon BWROG EPGs ensures proper guidance to the Operator on when it is appropriate to override automatic system controls. The acceptability of overriding automatic actions for analyzed transients and events in the Updated Safety Analysis Report (USAR) has been reviewed and found appropriate. Where automatic actions are authorized to be overridden by EOPs for certain USAR analyzed events, the discussion of these events in the USAR has been appropriately revised to reflect the EOP action.

Question 1b

Operational personnel should be instructed to not override the automatic action of ESFs unless continued operation of those ESFs will result in unsafe plant conditions (see Section 5A of this

[10] Text of NUREG position can be found in Bulletin 79-08.

bulletin); and not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

Response

Unit 2 EOPs specifically address these considerations.

Question 1c

All licensee Operators and plant management and supervisors with operational responsibilities should participate in this review and such participation shall be documented in plant records.

Response

As part of the plant personnel training program, training for mitigating core damage and use of the EOPs is provided and documented.

Question 2

Review the containment isolation initiation design and procedures and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

Response

This analysis has been completed and is described in Section 1.10.

Question 3

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) 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

Unit 2 EOPs describe how auxiliary heat removal systems are to be operated under conditions when feedwater is not available.

Question 4

Describe all uses and types of vessel level indication for both automatic and manual initiation to safety systems. Describe other redundant instrumentation which the observer might have to give the same information regarding plant status. Instruct

Operators to use other available information to initiate safety systems.

Response

EOPs provide for methods other than strictly RPV water level instruments to determine RPV water level. This is consistent with BWROG EPG (Revision 4), which has been sanctioned by the NRC by issuance of a SER. Additionally, Section 7 of the FSAR provides a description of the vessel level indication which provides automatic initiation of safety systems. Unit 2 has provided a listing of the post-accident monitoring systems which are used to provide plant status in Section 7.5.

Question 5

Review the action directed by the operating procedures and training instructions to ensure that Operators do not override automatic actions of ESFs, unless continued operation of ESFs will result in unsafe plant conditions (e.g., vessel integrity).

Response 5a

EOPs provide direction for when it is appropriate to override automatic actions of ESFs. The acceptability of overriding automatic actions for analyzed transients and events in the USAR has been reviewed and found appropriate. Where automatic actions are authorized to be overridden by EOPs for certain USAR analyzed events, the discussion of these events in the USAR has been appropriately revised to reflect the EOP action.

Question 5b

Operators are provided additional information and instructions to not rely upon vessel level indication alone for manual actions, but to also examine other plant parameter indications in evaluating plant conditions.

Response

The EOPs incorporate this additional guidance.

Question 6

Review all safety-related valve positioning requirements and positive controls to ensure that valves remain positioned opened or closed in a manner to ensure the proper operation of ESFs. Also review safety-related procedures, such as those for maintenance testing, plant and system startup, and the 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 all operational modes.

Response

A review of safety-related valve positions, positioning requirements, and positive controls to ensure the valves remain positioned (opened or closed) in a manner to ensure the proper operation of ESFs has been conducted as part of the design review process. (Also see Section 7.3.)

Procedures for maintenance, plant system startup, and periodic surveillance procedures and the verification that valves are returned to their correct positions are addressed in Section 1.10 of the FSAR.

Question 7

Review your operating modes and procedures for all systems designed to transfer potentially-radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other releases of radioactive liquids and gases will not occur inadvertently. In particular, ensure that such an occurrence would not be caused by resetting of ESFs, instrumentation. List all such systems and indicate a) whether interlocks exist to prevent transfer when high radiation exists; b) whether such systems are isolated by the containment isolation signal; c) the basis on which continued operability of the above features is assured.

Response

The answer to this question is provided as described in Section 1.10. Safety-related isolation signals will be periodically tested in accordance with the Technical Specifications.

Question 8

Review and modify, as necessary, your maintenance and test procedures to ensure that they require a) verification by test or inspection of the operability of redundant and safety-related systems prior to removal of any safety-related system from service; b) verification of the operability of all safety-related systems when they are returned to service following maintenance or test; and c) explicit notification of involved reactor operational personnel whenever a safety-related system is removed and returned to service.

Response

Unit 2 will incorporate this guidance in the maintenance and test procedures. This information and a commitment to incorporate these requirements are described in Section 1.10.

Question 9

Review your prompt reporting procedures for NRC notification to assure that the NRC is notified within 1 hr of the time the reactor is not in control or expected condition of operation. Further, at that time, and open continuous communication shall be established and maintained with the NRC.

Response

The Site Emergency Plan and the procedures used for its implementation describe the communications necessary during emergency conditions at Unit 2.

Question 10

Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

Response

Unit 2 uses an inerted containment. Hydrogen recombiners are used to remove hydrogen gas from the primary containment. Reactor vessel high-point vents are provided to allow hydrogen to be released into the primary containment and thereby removed by the hydrogen recombiners. EOPs contain a primary containment hydrogen control section. This procedure (based upon BWROG EPG) directs the operation of containment vent and purge, recombiners and containment sprays when appropriate.

Question 11

Propose changes as required to those Technical Specifications which must be modified as a result of your implementing the items above.

Response

Technical Specifications which will be submitted for Unit 2 will reflect any changes in procedures or design changes which have resulted from the TMI accident.

II.K.3.3 FAILURE OF PORV OR SAFETY VALVE TO CLOSE

FSAR Cross-Reference

Section 6.3

NUREG-0737 Position[11]

Assure that any failure of a power-operated relief valve (PORV) or safety valve to close will be reported to the NRC promptly.

[11] Text of NUREG position can be found in Bulletin 79-08.

All challenges to the PORVs or safety valves should be documented in the annual report.

Nine Mile Point Unit 2 Position

Failures of primary system relief or safety valves to close will be reported to the NRC via the LER system.
Additionally, a brief tabulation of all challenges to primary system relief and safety valves occurring during the year will be provided in the annual report.

II.K.3.13 CHANGE RCIC INITIATION LOGIC

FSAR Cross-Reference

Sections 5.4.6, 7.4

NUREG-0737 Position

Currently, the RCIC system and the 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 systems 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 analyses.

Provide sufficient supporting analysis to demonstrate that the systems, as modified, would not degrade proper system functions.

Nine Mile Point Unit 2 Position

Unit 2 utilizes the HPCS in lieu of HPCI.

Analysis by the BWROG and GE-NED on separation of initiation setpoints for HPCS/RCIC shows that there will be insignificant change to the reactor vessel's thermal cycle history. Therefore, separation of initiation setpoints (low reactor water level) will not be implemented at Unit 2.

The RCIC system will restart on low reactor water level (Level 2) following a system trip on high reactor water level (Level 8). The steam supply valve will shut automatically in lieu of the turbine trip valve. The turbine trip valve will still be armed to shut down the RCIC turbine when system requirements necessitate shutdown.

The implementation of the RCIC modification is based upon the BWROG and GE-NSD evaluation of NUREG-0737 Task II.K.3.13B in late 1980.

II.K.3.15 HPCI, RCIC PIPE BREAK

FSAR Cross-Reference

Sections 5.4.6, 6.3, 7.4

NUREG-0737 Position

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 that 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 (NUREG-0737).

Nine Mile Point Unit 2 Position

The Unit 2 design uses a HPCS with an electric motor-driven pump rather than a steam turbine-driven pump. Therefore, Unit 2 does not have this problem as it relates to the HPCI system.

The RCIC pipe break detection circuitry has been modified using timers to prevent isolation of the system caused by pressure spikes during system initiation.

II.K.3.16 RELIEF VALVE CHALLENGES

FSAR Cross-Reference

Sections 5.2, 5.4, 15.1.4

NUREG-0737 Position

The record of relief valve failures to close for all BWRs in the past 3 yr of plant operation is approximately 30 in 73 reactor-years (0.41 failures/reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small break LOCA. The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures/challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

1. Additional anticipatory scram on loss of feedwater.

2. Revised relief valve actuation setpoints.

3. Increased emergency core cooling flow.

4. Lower operating pressures.

5. Earlier initiation of ECCS.

6. Heat removal through emergency condensers.

7. Offset valve setpoints to open fewer valves/challenge.

8. Installation of additional relief valves with a block or isolation valve feature to eliminate opening of the SRVs, consistent with the ASME Code.

9. Increasing the high steam line flow setpoint for MSIV closure.

10. Lowering the pressure setpoint for MSIV closure.

11. Reducing the testing frequency of the MSIVs.

12. More stringent valve leakage criteria.

13. Early removal of leaking valves.

An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the forementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Failure of the PORV to reclose during the TMI-2 accident resulted in damage to the reactor core. As a consequence, relief valves in all plants, including BWRs, are being examined with a view toward their possible role in a small break LOCA.

The SRVs are dual-function pilot-operated relief valves that use a spring-actuated pilot for the safety function and external air diaphragm-actuated pilot for the relief function.

The operating history of the SRV 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. These changes, which are shown to decrease the number of challenges without compromising the performance of the valves or other systems, should be implemented.

The failure of a SRV to reclose will be the most probable cause of a small break LOCA. Based on the above guidance and clarification, results of a detailed evaluation should be submitted to the staff. The licensee shall document the proposed system changes for staff approval before implementation.

Nine Mile Point Unit 2 Position

The BWROG evaluated the NRC-suggested modifications listed earlier. Section 4.3 of the BWROG study (March 31, 1981) states: "For comparing the various valves, the Three-Stage Target Rock Valve was taken as the benchmark valve with an assumed normalized factor of 1.0 for probability to stick open when challenged." Section 4.3.3 compares Crosby and Dikkers SRVs to the three-stage target rock, and states: "Based on valve qualification test data and limited operating experience, a normalized factor of 0.125 was assigned for their relative probability to stick open, when challenged." Since the Unit 2 design includes Dikkers SRVs, a reduction of challenges relative to the benchmark valve, of roughly one order of magnitude, is achieved; therefore, the intent of the NUREG is satisfied.

The SER for Item II.K.3.16 of NUREG-0737 specifies that the following system or operational modifications are acceptable for reducing SRV challenges and failures:

1. Use low-low set (LLS) relief logic or equivalent manual action.

2. Lower the RPV water level isolation setpoint for MSIV closure from Level 2 to Level 1.

3. Increase SRV simmer margin (the difference between the SRV setpoint pressure and the vessel operating pressure).

4. Institute a preventive maintenance program.

The generic BWR EPGs instruct the Operator to hold open a SRV beyond the normal reclosure pressure to stop SRVs from cycling, and thus minimize the number of challenges to the system. This is the manual equivalent of the LLS relief logic. The plant EOPs incorporate this particular instruction of the EPGs.

Closure of the MSIVs is initiated when reactor water level reaches Level 1.

The SER specifies a recommended simmer margin of 120 psi. The plant vessel operating pressure is less than 1,020 psig, whereas the lowest spring set pressure is 1,165 psig. Consequently, for the limiting SRV under limiting operating pressure, a simmer margin of at least 120 psi is maintained.

II.K.3.17 REPORT ON OUTAGES OF EMERGENCY CORE COOLING SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

FSAR Cross-Reference

Section 6.3 and the Technical Specifications

NUREG-0737 Position

Several components of the ECCSs are permitted by Technical Specifications to have substantial outage times (e.g., 72 hr for one diesel generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECCSs. Licensees should submit a report detailing outage dates and lengths of outages for all ECCSs for the last 5 yr of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

The present Technical Specifications contain limits on allowable outage times for ECCSs and components. However, there are no cumulative outage time limitations on these same systems. It is possible that emergency core cooling 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 ECCSs for the last 5 yr 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) cause of the outage; 3) ECCSs or components involved in the outage; and 4) corrective action taken. Test and maintenance outages should be included in the above listings which are to cover the last 5 yr of operation. The licensee should propose changes to improve the availability of emergency core cooling equipment, if needed.

Applicant for an operating license shall establish a plan to meet these requirements.

Nine Mile Point Unit 2 Position

Unit 2 will report ECCS outages via LERs and Annual Summary Reports as required by Technical Specifications.

II.K.3.18 ADS ACTUATION LOGIC

FSAR Cross-Reference

Sections 6.3, 7.3

NUREG-0737 Position

The 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 HPCI or HPCS system flow exists and a low-pressure ECCS is running. This logic would complement, not replace, the existing ADS actuation logic.

Nine Mile Point Unit 2 Position

Unit 2 has participated in the BWROG evaluation of logic modifications to simplify ADS actuation.

Based on the BWROG design modifications found to be acceptable by the NRC staff, Unit 2 has removed the high drywell pressure trip in conjunction with the addition of a manual switch to inhibit ADS actuation (Option 2, NEDE-30045).

II.K.3.21 CORE SPRAY AND LPCI AUTO RESTART

FSAR Cross-Reference

Sections 6.3, 7.3

NUREG-0737 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.

Modification of system design should be made in accordance with the requirements set forth in Sections 4.12, 4.13, and 4.16 of IEEE-279-1971 with regard to protective function bypasses and completion of protective action once initiated.

Nine Mile Point Unit 2 Position

BWROG and GE have taken the position that LPCS and LPCI modifications should not be made.
The Unit 2 project will not modify the LPCS and LPCI but will include HPCS modification for automatic restart capability. Automatic restart occurs upon loss of reactor water inventory after having been stopped by the Operator, or if the initiation signal is still present or reoccurs.

Definition of HPCS modifications:

1. The HPCS pump will auto-restart on low reactor water level (Level 2) if the pump has been stopped manually. Four separate transmitter/trip units energize individual relays, arranged in a one-out-of-two twice logic configuration, to provide the automatic start and auto-restart initiation signal.

2. The HPCS pump auto-restart on high drywell pressure will be blocked, unless the drywell pressure decreases below its setpoint and then again increases above its setpoint.

3. When drywell pressure decreases below its setpoint, all reset features on the HPCS system will be removed, returning HPCS logic to its original state.

4. If the HPCS pump is started (manually or automatically), it can only be manually stopped. The injection valve is closed on reactor vessel level high (Level B), and the pump will continue to run in the recirculation mode.

II.K.3.22 RCIC SUCTION SOURCE

<u>FSAR Cross-Reference</u>

Sections 5.4.6, 7.4

<u>NUREG-0737 Position</u>

The RCIC system takes suction from the condensate storage tank (CST) with manual switchover to the suppression pool when the CST level is low. This 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 CST to the suppression pool.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 project has implemented the NRC position to automatically transfer RCIC suction source. CST low water

inventory automatically initiates transfer of the suction of the RCIC pump to the suppression pool.

The modification of the RCIC system allows automatic switchover of pump suction from the CST to the suppression pool if the RCIC pump suction pressure falls to a preset low level. Two pressure transmitters are used to detect low pressure at the RCIC pump suction. If either transmitter senses low pressure (indicating low CST level), pump suction is automatically transferred to the suppression pool. These are different transmitters/trip units from those that activate switchover for the HPCS system. The CST suction valve will be signaled to close upon opening of the suppression pool suction valve.

The P&ID, Figure 5.4-9, and elementary diagram have been revised to reflect a relocation of the transmitter to the pump suction line.

II.K.3.24 RCIC AND HPCI SUPPORT POWER

<u>FSAR Cross-Reference</u>

Section 9.4

<u>NUREG-0737 Position</u>

Long-term operation of the RCIC and HPCI systems may require space cooling to maintain the pump room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of ac power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite ac power to their support systems, including coolers, for at least 2 hr.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 ECCS design employs a cubicle arrangement to ensure physical, electrical, and environmental separation of each portion of the ECCS. The RCIC system is also located within a separate cubicle. The HPCS pump room is cooled by either of two fully redundant Category I unit space coolers. The remaining ECCS pump rooms and the RCIC pump room are each cooled by one Category I unit space cooler with an additional cooler provided as a spare. These coolers are part of the reactor building HVAC system which utilize cooling water from the SWP system. The safety-related portions of the SWP system are powered from the standby diesel generators following a LOOP; therefore, a reliable supply of cooling water is provided. Likewise, the control systems involved in the operation of the unit coolers also receive their power from the diesel generators following a LOOP. This design assures that the pump room temperatures are maintained within normal limits for an indefinite period following a complete LOOP.

II.K.3.25 RCS PUMP SEAL DESIGN

FSAR Cross-Reference

Sections 5.4, 9.2.1

NUREG-0737 Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the RCS pump seal coolers. The pump seals should be designed to withstand a complete loss of ac power for at least 2 hr. Adequacy of the seal design should be demonstrated.

The intent of this position is to prevent excessive loss of reactor coolant inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be a LOOP. If seal failure is the consequence of loss of cooling water to the RCS pump seal coolers for 2 hr, due to a LOOP, one acceptable solution would be to supply emergency power to the component cooling water pump.

Nine Mile Point Unit 2 Position

The Unit 2 RCS pumps incorporate a dual mechanical seal assembly to control leakage around the rotating shaft. Each assembly consists of two seals built into a cartridge, each seal designed for full pump design pressure and capable of limiting leakage in the event that the other seal should fail.

During normal operation, cooling water to the RCS pump seals is provided from two sources, the RBCLCW system (for the seal assembly heat exchanger), and the CRD system (for the seal purge injection system). The combination of these two cooling systems normally maintains the seal temperatures at approximately 120°F.

Deterioration of pump seals begins to occur when seal temperatures exceed 250°F. With either of the seal cooling systems operable, the seal temperatures remain well below 250°F and no seal deterioration is expected. During a LOOP, both cooling systems would be lost. Emergency power is available to the RBCLCW and the CRD pumps via the stub bus, which can be connected to the emergency diesel generators. Operator action is required to connect the CRD pumps to the emergency power source to reestablish cooling water flow to the seals of the idle RCS pumps.

Loss of seal cooling and associated seal deterioration would not occur as a result of a LOOP.

Even if both cooling systems were lost and a total failure of the pump seals did occur, the BWROG evaluation of this item demonstrated that the resulting primary coolant leakage would be well within the capability of the normal or emergency reactor

water level control systems. Unit 2 has reviewed the BWROG evaluation (transmitted by letter from D. B. Waters to D. G. Eisenhut, dated May 22, 1981, and supplemented by letter from T. J. Dente to D. G. Eisenhut, dated September 21, 1981) and endorses its applicability to the Unit 2 project.

II.K.3.27 COMMON WATER LEVEL REFERENCE

FSAR Cross-Reference

Section 7.5 and the Technical Specifications

NUREG-0737 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 TAF is a reasonable reference point (NUREG-0737).

Nine Mile Point Unit 2 Position

Unit 2 utilizes a common water level reference elevation at 380.69 in above the vessel invert elevation. This reference point corresponds to the top of the upper core support plate. All five level instrumentation ranges (shutdown, upset, wide, narrow, and fuel) utilize this reference.

II.K.3.28 ADS ACCUMULATORS

FSAR Cross-Reference

Sections 5.2, 6.3, 9.3.1

NUREG-0737 Position

Safety analysis reports claim that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressure. GE has also stated that the ECCSs are designed to withstand a hostile environment and still perform their function for 100 days following an accident. The licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments, 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.

Nine Mile Point Unit 2 Position

The primary source of pneumatic supply and leakage makeup for the ADS accumulators will be from two nitrogen storage tanks located outside the reactor building. Long-term post-accident supply and leakage makeup will be provided by two bottled nitrogen connections, also located outside the reactor building. Two Category I nitrogen accumulator tanks are located in the reactor building and are pressurized from the nitrogen storage tanks. These two large accumulators provide pneumatic supply and leakage makeup for the seven smaller ADS accumulators located inside the primary containment. This arrangement provides sufficient time to place the bottled nitrogen system into service if the plant condition requires long-term ADS operation.

The ADS valves, including pilot operators, are designed to withstand a hostile environment and still perform their safety function for 100 days following an accident. Long-term post-accident operation requires only three of the seven ADS valves to be operable. A single failure in one of the pneumatic supply lines will not prevent the ADS from accomplishing its safety function in either the short or long term.

The following is a comparison to Enclosure 13 of a NRC letter to NMPC, dated March 29, 1983, Qualification of ADS Accumulator System Valves.

1.0 Criteria - Number of Actuations

1.1 Unit 2 Position

Actuations

1.1.1 The ADS accumulators can provide at least one SRV actuation at drywell design pressure of 45 psig and with reactor pressure at 0 psig, using only valve accumulator inventory. This is equivalent to at least six SRV actuations at drywell pressure of 0.75 psig. These accumulators are also capable of opening the ADS SRVs one time at drywell pressure of 45 psig and holding them open for at least 13.8 hr during post-accident condition.

System Description

1.1.2 See the ADS accumulator system description given above. The detailed design and operation for this system is also given in Sections 5.2, 6.3, and 9.3.1.

2.0 Criteria - Leakage Criteria

2.1 Unit 2 Position

Basis for Leakage Criteria

2.1.1 The basis for the allowable leakage criteria of 1 scfh per SRV is to ensure adequate accumulator capacity for one ADS actuation for a period of 4 hr following an intermediate or small break, without recharging the accumulator. As noted above, Unit 2 ADS valve accumulators can maintain the ADS SRVs open for approximately 13.8 hr with an assumed leakage of 1 scfh.

Leakage Criteria Margin/Increase Leakage Rate

2.1.2/3 Experience from previous environmental qualification and NUREG-0588 tests simulating harsh and seismic environment currently being conducted shows that the SRV pneumatic operator leakage is approximately 0.5 scfh. This ensures that the leakage rate does not increase following an accident.

Safety-Related Equipment

2.1.4 No credit is taken for nonsafety-related equipment and instrumentation when establishing the allowable leakage criteria.

3.0 Criteria - Periodic Leak Testing

3.1 Unit 2 Position

Periodic Leak Test

3.1.1 The periodic leak testing of the ADS accumulator system will be performed as described in Section 6.3.4.2.2.

Backup System Description

3.1.2 As discussed in Section 9.3.1.4, in the event that the nitrogen in the ADS valve accumulators is depleted, a 5-day supply is available to the accumulators from the nitrogen receiver tanks located in the secondary containment. In addition to that, there are provisions for recharging the ADS nitrogen receiver tanks through their individual emergency supply lines located in the missile-protected area outside the standby gas treatment building from special emergency tube trailer supply connections. These special emergency recharging lines are classified as seismic Category I, Safety

Class 3. Thus, this backup system meets the overall requirements of the ADS system.

Alarms and Instrumentation

3.1.3 A description of alarms and instrumentation associated with the ADS accumulator system is provided in Section 9.3.1.4.

Backup System Test

3.1.4 Testing of the backup nitrogen system will be included with the testing of the ADS accumulator system.

Alarm Surveillance

3.1.5 The surveillance testing of alarms and instrumentation will be performed as discussed in Section 4.0.

Leakage Rate Verification

3.1.6 The ADS accumulator system and N_2 makeup supply are designed to provide adequate makeup for leakage under normal operating and post-accident conditions. The Unit 2 analysis has accounted for this leakage and has verified that the ADS will perform its required safety function.

4.0 Criteria - Technical Specification

4.1 Unit 2 Position

Limiting conditions for operation, associated action statements, and surveillance requirements for the ADS are contained in the Unit 2 Technical Specifications.

5.0 Seismic and Environmental Qualification

5.1 Unit 2 Position

5.1.1 Seismic Qualification

All portions of the ADS supply system are seismically analyzed and supported in accordance with safe shutdown earthquake (SSE) design requirements. A detailed description is provided in Section 9.3.1.4.

5.1.2 Environmental Qualification

All ADS equipment and instrumentation are environmentally qualified to meet performance requirements under normal, abnormal, accident, and post-accident conditions. The environmental qualification program for Unit 2 is discussed in Chapter 3.

5.1.3 Safety-Related Equipment

The ADS system is designed to withstand an accident environment and still perform its safety-related function for 100 days following an accident. No credit is taken for nonsafety-related equipment and instrumentation for their function during or following an accident.

II.K.3.30 PLANT-SPECIFIC SMALL BREAK LOCA ANALYSIS

FSAR Cross-Reference

Section 15.6.5

NUREG-0737 Position

The analysis methods used by NSSS vendors and/or fuel suppliers for small break LOCA analysis for compliance with Appendix K to 10CFR50 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 (NUREG-0737).

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 10CFR50, was needed. This included providing predictions of Semiscale Test S-07-10B and 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. As an example, a model that presently does not properly account for horizontal countercurrent two-phase flow in the hot leg piping should either be revised to properly account for the phenomenon, or demonstrated to produce a conservative result for the entire spectrum of small breaks considered.

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 (NUREG-0635, -0565, -0626, -0611, and -0623). These concerns should be reviewed in total by each holder of an approved ECCS model and addressed in the evaluation as appropriate.

The recent tests include the entire semiscale small break test series and LOFT Tests (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., ORNL core uncovery 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 submitting this information for staff review and approval.

Nine Mile Point Unit 2 Position

The response to the NRC specific small break model concerns was provided at a meeting between the NRC and GE on June 18, 1981, documented by GE[1]. The NRC agreed that such a meeting could form the basis for final closure of Task II.K.3.30[2]. GE demonstrated that based on the two-loop test apparatus (TLTA) small break test results and sensitivity studies, the existing GE small break LOCA model already satisfies the concerns of NUREG-0626 and is in compliance with 10CFR50 Appendix K. Therefore, the model is acceptable relative to the concerns of Item II.K.3.30 and no model changes need to be made to satisfy this item.

REFERENCES

1. Letter from R. H. Buckholz (GE) to D. G. Eisenhut (NRC), NUREG-0737, Item II.K.3.30 - final program, dated June 26, 1981.

2. Telecon from F. Hayes (GE) and D. Dennison (GE) to W. Hodges (NRC), dated June 11, 1981.

II.K.3.31 UPGRADE OF NON-ECCS ITEMS USED IN SB LOCA ANALYSIS

FSAR Cross-Reference

Section 15.6.5

NUREG-0737 Position

Plant-specific calculations using NRC-approved models for small break LOCAs as described in Task II.K.3.30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees (NUREG-0737).

Equipment used to mitigate a small break LOCA must be of the same reliability and redundancy as RPS or ECCS equipment. All cooling systems required to prevent uncovering the core must be qualified as ECCSs by incorporating diverse isolation signals.

Nine Mile Point Unit 2 Position

The results of the Unit 2-specific small break LOCA analysis are presented in Section 15.6.5. This analysis was performed with the use of a NRC-approved small break LOCA model (Task II.K.3.30).

All cooling systems for which credit is taken in the model to mitigate the consequences of the LOCA are fully-qualified ECCSs. No credit is taken for non-ECCS components or systems (e.g., RCIC).

II.K.3.44 TRANSIENT ANALYSIS

FSAR Cross-Reference

Section 15.0

NUREG-0737 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 uncovery. Transients that result in a stuck-open relief valve should be included in this category.

Nine Mile Point Unit 2 Position

The generic report prepared by GE on behalf of the BWROG in response to TMI Action Item II.K.3.44, Evaluation of Anticipated Transients With Single Failure, was reviewed for applicability to Unit 2. Specifically included in the review were the assumptions and initial conditions utilized in the BWR 5 analyses.

The worst-case transient for Unit 2 is loss of feedwater flow (LOFW) with single failure of the HPCS. The assumption of decay heat, 105-percent power level, feedwater coastdown time, CRD flow, etc., are all applicable to Unit 2.

The overall expected response for the LOFW transient for Unit 2 is the same shown in Reference 1 for various BWR 5 cases. It is shown that the core remains covered for any transient with the worst single failure. This is achieved without any Operator action to manually initiate ECCS or other inventory makeup systems.

For the bounding LOFW event, studies which include even more degraded conditions such as failure of HPCS and one SORV[1] show that the core will remain covered and no fuel failure will occur.

REFERENCE

1. Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors, NEDO-24708A, Revision 1, December 1980.

II.K.3.45 PARTIAL USE OF ADS

FSAR Cross-Reference

Section 5.2.2

NUREG-0737 Position

Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown (NUREG-0733).

Nine Mile Point Unit 2 Position

The Unit 2 project as a member of the BWROG endorses the position statement and analysis prepared by GE on behalf of the BWROG and submitted to the NRC on December 29, 1980.

II.K.3.46 RESPONSE TO ACRS CONSULTANT CONCERNS

FSAR Cross-Reference

Section - General

NUREG-0737 Position

GE should provide a response to the Michelson concerns as they relate to BWRs. See NUREG-0660, Appendix C, Table c.3, Item 46 (Reference 1) and NUREG-0626, Section 4, Item A.17 (Reference 6c).

Nine Mile Point Unit 2 Position

GE reviewed the questions posed by Mr. Michelson and prepared a generic BWR response on behalf of the BWROG. This response was submitted to the NRC and was found to be acceptable (refer to June 12, 1981, letter from Mr. D. G. Eisenhut to Mr. D. B. Waters).

Unit 2 endorses the responses of GE. The only instance in which the design deviates from the generic design described in the response is for the question of ECCS pump seal damage and leakage following a small break LOCA coincident with a LOOP (Question 12). The response is applicable to Unit 2 except as it pertains to RHR pump seal cooling.

The Unit 2 RHR pump seal coolers require external cooling water. During normal RHR operation, this cooling water is supplied by the RBCLCW system. If this system is lost for some reason, such as a LOOP, the cooling water supply can be remote manually transferred (from the main control room) to the service water system. The service water system receives its power from the standby diesel generators following a LOOP; thus a supply of cooling water is always ensured. Therefore, RHR pump seal damage and leakage following a small break LOCA coincident with a LOOP is not a valid concern for the unit project. Even if a seal failure were to occur, the leak detection and isolation capability described in the response is applicable for Unit 2.

III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

FSAR Cross-Reference

Section 13.3

NUREG-0737 Position[12]

Each operating nuclear power plant shall maintain an onsite TSC, separate from and in close proximity to the control room, that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the

[12] Test of NUREG position can be found in NUREG-0578 and NUREG-0660.

event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the TSC. Records that pertain to the as-built conditions and layout of structures, systems, and components shall be readily available to personnel in the TSC.

An Operational Support Center (OSC) shall be established separate from the control room and other ERFs as a place where operations support personnel can assemble and report to in an emergency situation to receive instructions from the operating staff. Communications shall be provided between the OSC, TSC, ERF, and control room.

An EOF (near-site) will be operated by the licensee for continued evaluation and coordination of all licensee activities related to an emergency having or potentially having environmental consequences. The EOF must meet habitability requirements to ensure that personnel can remain in the facility throughout the entire course of the accident including evacuation of the surrounding area. The facility will have sufficient space to accommodate representatives from federal, state, and local governments as appropriate. In addition, the major state and local response agencies may provide for data analysis jointly with the Operator at this location. The EOF will provide information needed by federal, state, and local authorities for implementation of offsite emergency plans in addition to a centralized meeting location for key representatives from the agencies.

<u>Nine Mile Point Unit 2 Position</u>

The Unit 2 project has established the ERF to include the TSC, the OSC, and the EOF. These facilities are described in Section 13.3 of the FSAR and in the Site Emergency Plan.

III.A.2 LONG-TERM EMERGENCY PREPAREDNESS

<u>FSAR Cross-Reference</u>

Section 13.3

<u>NUREG-0737 Position</u>

Each nuclear facility shall upgrade its emergency plans 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 is 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.

The final regulations on emergency planning require the submittal and implementation of the radiological emergency response plans of licensees and state and local entities written the plume exposure and ingestion emergency planning zones (EPZ).

NUREG-0654 has been revised to include changes developed from team reviews and comments obtained during the comment period. The revised NUREG-0654 establishes the schedule for installation of meteorological equipment to meet a prescribed implementation date (also see proposed Revision 1 to RG 1.23).

In accordance with Task III.A.1.1, Upgrade Emergency Preparedness, each nuclear power facility was required to immediately upgrade its emergency plans with criteria provided October 10, 1979, as revised by NUREG-0654 (FEMA-REP-1, issued for interim use and comment, January 1980). New plans were submitted by January 1, 1980, using the October 10, 1979, criteria. Reviews were started on the upgraded plans using NUREG-0654. Concomitant to these actions, amendments were developed to 10CFR50 and Appendix E to 10CFR50 to provide the long-term implementation requirements. These new rules were issued in the Federal Register on August 19, 1980, with an effective date of November 3, 1980. The revised rules delineate requirements for emergency preparedness at nuclear reactor facilities.

NUREG-0654 (FEMA-REP-1), Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, provides detailed items to be included in the upgraded emergency plans and, along with the revised rules, provides for meteorological criteria, means for providing for a prompt notification to the population, and the need for ERFs (see Task III.A.1.2).

Implementation of the new rules levied the requirement for the licensee to provide procedures implementing the upgraded emergency plans to the NRC for review. Publication of Revision 1 to NUREG-0654 (FEMA-REP-1) which incorporates the many public comments received is expected in October 1980. This is the document that will be used by the NRC and FEMA in their evaluation of emergency plans submitted in accordance with the new NRC rules.

NUREG-0654, Revision 1; NUREG-0696, Functional Criteria for Emergency Response Facilities; and the amendments to 10CFR50 and Appendix E to 10CFR50 regarding emergency preparedness, provide more detailed criteria for emergency plans, design, and functional criteria for ERFs and establish firm dates for submission of upgraded emergency plans for installation of prompt notification systems. These revised criteria and rules supersede previous Commission guidance for the upgrading of emergency preparedness at nuclear power facilities.

Revision 1 to NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, provides meteorological criteria to fulfill, in part, the standard that "Adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use" (see 10CFR50.47). The position in Appendix 2 to NUREG-0654 outlines four essential elements that can be categorized into three functions: measurements, assessment, and communications.

Proposed Revision 1 to RG 1.23, Meteorological Measurements Programs in Support of Nuclear Power Plants, has been adopted to provide guidance criteria for the primary meteorological measurements program consisting of a primary system and secondary system(s) where necessary, and a backup system. Data collected from these systems are intended for use in the assessment of the offsite consequences of a radiological emergency condition.

Appendix 2 to NUREG-0654 delineates two classes of assessment capabilities to provide input for the evaluation of offsite consequences of a radiological emergency condition. Both classes of capabilities provide input to decisions regarding emergency actions. The Class A capability should provide information to determine the necessity for notification, sheltering, evacuation, and, during the initial phase of a radiological emergency, making confirmatory radiological measurements. The Class B capability should provide information regarding the placement of supplemental meteorological monitoring equipment, and the need to make additional confirmatory radiological measurements. The Class B capability shall identify the areas of contaminated property and foodstuff requiring protective measures, and may also provide information to determine the necessity for sheltering and evacuation.

Proposed Revision 1 to RG 1.23 outlines the set of meteorological measurements that should be accessible from a system that can be interrogated; the meteorological data should be presented in the prescribed format. The results of the assessments should be accessible from this system; this information should incorporate human factors engineering in its display to convey the essential information to the initial decision makers and subsequent management team. An integrated system should allow the eventual incorporation of effluent monitoring and radiological monitoring information with the environmental transport to provide direct dose consequence assessments.

Requirements of the new emergency preparedness rules under Paragraphs 50.47 and 50.54 and the revised Appendix E to Part 50, taken together with NUREG-0654 Revision 1 and NUREG-0696, when approved for issuance, go beyond the previous requirements for meteorological programs. To provide a realistic time frame for implementation, a staged schedule has been established with compensating actions provided for interim measures.

Nine Mile Point Unit 2 Position

Provision for long-term emergency preparedness has been incorporated for Unit 2 and is described in Section 13.3 of the FSAR and the Site Emergency Plan.

III.D.1.1 PRIMARY COOLANT OUTSIDE CONTAINMENT

FSAR Cross-Reference

Sections 5.4.6, 5.4.7, 6.3

NUREG-0737 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.

Applicants shall provide a summary description, together with initial leak test 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.

Systems that should be leak tested are as follows (any other plant system that has similar functions or post-accident characteristics, even though not specified herein, should be included):

1. RHR.

2. Containment spray recirculation.

3. High-pressure injection recirculation.

4. Containment and primary coolant sampling.

5. RCIC.

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 that are excluded from the program and provide justification for exclusion.

Testing of gaseous systems should include helium leak detection or equivalent testing methods.

A program should be considered to reduce leakage potential release paths due to design and Operator deficiencies as discussed in our letter dated October 17, 1979, to all operating nuclear power plants regarding North Anna and related incidents.

Nine Mile Point Unit 2 Position

A program is being developed to monitor leakage from systems outside the containment which could be used to transport highly-radioactive fluids in a post-accident condition. This program will include the following features:

1. The implementation of a periodic visual inspection program consisting of a combination of general inspections and detailed system walkdown of liquid and steam systems. These inspections shall be performed on accessible portions of applicable systems during system operational testing or by evaluation of leakage at lower pressures during operation.

2. Systems containing gases are to be tested by use of tracer gases (helium, freon or DOP), or by pressure decay testing or by metered makeup tests.

   The standby gas system is exempted from the above test because the bulk of the system operates under vacuum, i.e., the spread of radioactivity is suppressed, and the system surveillance tests indirectly verify the system integrity upstream of the fans. The portion of the system downstream of the fans and the recirculation loops will either be inspected for leaks by a snoop test or any of the above tests will be used for leakage detection.

3. An aggressive maintenance program will be used to assign high priorities to leakage-related maintenance work requests (MWRs).

4. Preparation of systems list, identifying specific methods used to test systems, the system involved, and frequency of testing.

5. Records will be maintained on tests and inspections performed and leakage-related corrective maintenance items. These records will be used to identify chronic and generic leakage problems in order to implement modifications and/or corrective maintenance measures to keep leakage as low as practical.

These measures will be implemented prior to full power operation. Four months prior to fuel load, Unit 2 will submit to the NRC staff a report summarizing the program and all recorded leakage obtained during preoperational testing, as well as corrective maintenance performed as a direct result of this leakage evaluation. The report will also identify general leakage criteria to be applied during the first fuel cycle as the basis for implementing corrective maintenance actions. Prior to the start of the second fuel cycle, Unit 2 will revise the general criteria, as necessary, based on the experience gained during the Unit 2 first fuel cycle. The revised criteria shall then be used as the basis for long-term leakage monitoring activity at Unit 2.

III.D.3.3 IN-PLANT RADIATION MONITORING

FSAR Cross-Reference

Section 12.5

NUREG-0737 Position

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.

Each applicant for a fuel-loading license to be issued prior to January 1, 1981, shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

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.

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 the presence of iodine that can be used to determine if respiratory protection is required. Care must be taken to ensure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

Nine Mile Point Unit 2 Position

The in-plant iodine concentration will be determined by using either portable, semiportable, or fixed air samplers to draw a known quantity of air through either a charcoal filter or silver zeolite cartridge. Fixed samplers are located on the control room ventilation air intakes and have a charcoal filter collection capability for radioiodine.

There shall be at least six semiportable CAMs, located on the reactor and radwaste building ventilation systems, equipped with charcoal cartridges for iodine collection and capable of detecting noble gas and particulate concentrations. On-line isotopic analysis monitors will be installed at the two gaseous effluent points and will have the capability of identifying the quantity of a specific isotope released through the reactor building, radwaste building, or turbine building ventilation systems. Also included shall be at least four portable air samplers with the capability of using either a charcoal filter or silver zeolite cartridge for collection of radioiodine.

Prior to analysis, the charcoal filters will be purged with bottled nitrogen or clean air to remove entrapped noble gases; this is not necessary for the silver zeolite sample. The sample will be counted according to normal operating health physics procedures using instrumentation capable of accurately measuring iodine concentrations. Instrumentation used for this analysis will be located in both the Unit 1 and Unit 2 counting rooms. At least one of these locations will remain a low contamination, low background area for all postulated accident conditions.

III.D.3.4 CONTROL ROOM HABITABILITY

<u>FSAR Cross-Reference</u>

Section 6.4

<u>NUREG-0737 Position</u>

In accordance with Task III.D.3.4 and control room habitability, licensees 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 DBA conditions (Criterion 19, Control Room, of Appendix A, General Design Criteria for Nuclear Power Plant, to 10CFR50).

All licensees must make a submittal to the NRC regardless of whether or not they met the criteria of the referenced SRP sections. The new clarification specifies that licensees that meet the criteria of the SRPs should provide the basis for their conclusion that SRP 6.4 requirements are met. Licensees may establish this basis by referencing past submittals to the NRC and/or providing new or additional information to supplement past submittals.

All licensees with control rooms that meet the criteria of the following sections of the SRP:

2.2.1, 2.2.2	Identification of Potential Hazards in Site Vicinity
2.2.3	Evaluation of Potential Accidents
6.4	Habitability Systems

shall report their findings regarding the specific SRP sections as explained below. The following documents should be used for guidance:

1. RG 1.78, Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release.

2. RG 1.95, Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release.

3. 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.

Licensees 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, licensees may reference their past submittals. Licensees should, however, ensure that these submittals reflect the current facility design and that the information requested in Attachment 1 is provided.

All licensees with control rooms that do not meet the criteria of the above-listed references, SRPs, regulatory guides, and other references. These licensees shall perform the necessary evaluations and identify appropriate modifications.

Each licensee 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 DBAs. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either onsite or within 5 mi of the plant site boundary. RG 1.78 lists the chemicals most commonly encountered in the evaluation of control room habitability but is not all inclusive.

The DBA radiation source term should be for the LOCA containment leakage and ESF leakage contribution outside containment as described in Appendix A and B of SRP Chapter 15.6.5. In addition, BWR facility evaluations should add any leakage from the MSIV (i.e., valve stem leakage, valve seat leakage, MSIV leakage control system release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering the staff recommendations in Section D of RG 1.96 (Revision 2) regarding MSIV leakage control systems. Other DBAs should be reviewed to determine whether they might constitute a more severe control room hazard than the LOCA.

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 licensee should submit information needed for an independent evaluation of the adequacy of the habitability systems. Attachment 1 lists the information that should be provided along with the licensee's evaluation.

Nine Mile Point Unit 2 Position

The existing design provides for control room habitability during DBAs. The following are provided:

1. Maintenance of positive pressure.

2. Two tight butterfly dampers in series in the outside air duct to the control room.

3. Filtration of intake air.

These features enable the Control Room Operator to isolate the control room. Additionally, those hazards involving toxic chemicals that could potentially threaten Unit 2 control room habitability were evaluated in accordance with NUREG-0737 and NUREG-0570; RG 1.78, 1.91, and 1.95; SRP (NUREG-0800) Sections 2.2.1 and 2.2.2, 2.2.3, and 6.4; Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19[1]; and 10CFR50, Criterion 19, Appendix A. All hazards within 5 mi of the site were included, and the results of field surveys and calculations were reviewed to assess the need for possible additional equipment.

The results of the analysis indicated that none of the toxic chemicals evaluated had the potential to incapacitate the Control Room Operators. These results are summarized in Table 2.2-8.

The results and comprehensiveness of the toxic chemical study relating to control room habitability and its focus on compliance with the NRC's position and regulatory guidelines indicate that further analysis of toxic chemical effects is not necessary.

REFERENCE

1. Murphy, K. G. and Campe, K. M. Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19, 13th Air-Cleaning Conference, August 1974.

1.11 ABBREVIATIONS AND ACRONYMS

Table 1.11-1 is a list of abbreviations used in this FSAR.

TABLE 1.11-1
(Sheet 1 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

AABC	Associated Air Balance Council
AAS	Breathing air system
ABA	Amplitude based algorithm
ABD	Auxiliary boiler blow down system
ABF	Auxiliary boiler feedwater and condensate system
ABH	Chemical feed auxiliary boiler system
ABM	Auxiliary boiler steam system
ACI	American Concrete Institute
ADH	Alternate decay heat
ADS	Automatic depressurization system
AIB	Arbitrary intermediate break
AIM	Analog isolator module
AISC	American Institute of Steel Construction
ALARA	As low as reasonably achievable
ALRA	Amended license renewal application
ALS	Aluminum sheath
AMP	Aging Management Program
AMSL	Above mean sea level
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOV	Air-operated valve
AP	Administrative procedure
AP	Annulus pressurization
API	Automatic priority interrupt
APRM	Average power range monitor
ARC	Condensate air removal system
ARI	Alternate rod insertion
ARMS	Area radiation monitoring system
ARS	Amplified response spectra
ART	Adjusted reference temperature
ART_{NDT}	Adjusted nil ductility transition reference temperature
ASR	Radwaste auxiliary steam system
ASS	Auxiliary steam system
ASTM	American Society for Testing and Materials
ATM	Analog trip module
ATWS	Anticipated transient without scram
BCD	Binary coded (signal)
BCP	Bottom center pressure
BOC	Beginning of cycle
BOP	Balance of plant
BPWS	Banked position withdrawal sequence
BSP	Backup stability protection

TABLE 1.11-1
(Sheet 2 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

BSW	Biological shield wall
BTP	Branch technical position
BWR	Boiling water reactor
BWROG	Boiling Water Reactor Owners' Group
BWRT	Backwash waste receiving tank
BWRVIP	Boiling Water Reactor Vessel and Internals Program
CAD	Containment atmosphere dilution (device)
CAM	Continuous air monitor
CAP	Corrective action program
CAV	Crack arrest verification
CBF	Cycle-based fatigue
CBMI	Clad/base metal interface
CBVCWS	Control building ventilation chilled water system
CCC	Control cell core
CCCWS	Closed-cycle cooling water system
CCP	Reactor building closed loop cooling water system
CCS	Turbine building closed loop cooling water system
CCW	Closed cooling water
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CFS	Condensate filtration system
CGA	Compressed Gas Association
CGCS	Combustible gas control system
CHF	Critical heat flux
CIV	Combined intermediate valve
CIVM	Collision-imported-velocity method
CLM	Main steam and feedwater chemical cleaning system
CLTP	Current licensed thermal power
CMAA	Crane Manufacturers' Association of America
CMFA	Common mode failure analysis
CMS	Containment atmosphere monitoring system
CN	Curve number
CNA	Auxiliary condensate system
CND	Condensate demineralizer - mixed bed system
CNM	Condensate system
CNS	Condensate makeup and drawoff system
CO	Condensation oscillation
CO_2	Carbon dioxide
COLR	Core Operating Limits Report

TABLE 1.11-1
(Sheet 3 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

CPR	Critical power ratio
CPS	Central processing system
CPS	Primary containment purge system
CRD	Control rod drive
CRDA	Control rod drop accident
CRDRL	Control rod drive return line
CRPI	Control rod position indication
CRS	Cold reheat system
CRS	Control Room Supervisor
CRT	Cathode ray tube
CRVICS	Containment and reactor vessel isolation control System
CSB	Cold storage building
CSH	High-pressure core spray system
CSL	Low-pressure core spray system
CSO	Chief Shift Operator
CST	Condensate storage tank
CUF	Cumulative usage factor
CVA	Consecutive valve actuation
CVCS	Chemical and volume control system
CWS	Circulating water system
DAC	Dominant area of concern
DAR	Design Assessment Report for Hydrodynamic Loads
DARS	Days after reactor shutdown
DASIE	Data acquisition system import export
DB	Design basis
DBA	Design basis accident
DBE	Design basis earthquake
DBFL	Design basis flood level
DCDT	Direct current differential transducer
DCRDR	Detailed control room design review
DER	Deviation/Event Report
DER	Double-ended rupture
DER	Reactor building equipment drains system
DET	Turbine equipment drains system
DFFR	Dynamic Forcing Functions Information Report
DFG	Diode function generator
DFM	Floor drains - miscellaneous buildings system
DFR	Reactor building floor drains system
DFT	Turbine building floor drains system
DFW	Radwaste building floor and equipment drains system
DG	Diesel generator

TABLE 1.11-1
(Sheet 4 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

DLF	Dynamic load factor
DM	Durability monitor
DOE	Department of Energy
DOP	Dioctylphthalate
DOT	Department of Transportation
DRF	Drywell floor seal system
DRMS	Digital radiation monitoring system
DRS	Drywell cooling system
DSC	Dry shielded canister
DSM	Moisture separator vents and drains system
DSR	Moisture separator reheater vents and drains system
DTM	Turbine plant miscellaneous drains system
DTUC	Digital transponding ultrasonic calibrator
DWS	Domestic water system
DZO	Depleted zinc oxide
EAB	Exclusion area boundary
ECA	Engineering change authorization
ECCS	Emergency core cooling system
ECN	Engineering change notice
ECP	Electro-chemical potential
ECT	Eddy current testing
EDG	Emergency diesel generator
EFCV	Excess flow check valve
EFPY	Effective full-power years
EGA	Air startup standby diesel generator system
EGF	Standby diesel generator fuel system
EGS	Standby diesel generator system
EHC	Electrohydraulic control
EIC	Energy Information Center
EMC	Electromagnetic compatibility
EMS RTU	Emergency management system remote terminal unit
EOC	End of cycle
EOF	Emergency Operations Facility
EOF	Equivalent occurrence factor
EOL	End of life
EOP	Emergency operating procedure
EPA	Electric protective assembly
EPDM	Ethylene-propylene-diene-monomer
EPG	Emergency procedure guideline
EPRI	Electric Power Research Institute
EPU	Extended power uprate
EPUTP	Extended power uprate thermal power
EPZ	Emergency planning zone
EQ	Environmental qualification

TABLE 1.11-1
(Sheet 5 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

EQML	Environmental Qualification Master List
EQPBD	Environmental Qualification Program Basis Document
ER-OLS	Environmental Report-Operating License Stage
ERF	Emergency response facility
ESEERCO	Empire State Electrical and Energy Research Corporation
ESF	Engineered safety feature
ESS	Extraction steam system
EST	Eastern standard time
ESW	Extremely severe weather
ETO	Engineering technical oversight
ETS	Emergency trip system EWEF Each way each face
FA	Fire area
FA	Full arc (mode of TCV operation)
FAC	Flow-accelerated corrosion
FAS	Fluid actuator system
FATT	Fracture appearance transition temperature
FC	Foot-candle
FCB	Flood control berm
FCD	Functional control diagram
FCV	Flow control valve
FDDR	Field deviation disposition request
FHA	Fire Hazards Analysis
FLC	Fuel loading chamber
FLECHT	Full-length emergency cooling heat transfer
FMEA	Failure modes and effects analysis
FMH	Fixture mounting height
FMP	Fatigue Monitoring Program
FOA	Forced-oil air
FOF	Engine driven fire pump - fuel oil system
FPAPDR	Full power adjusted power density ratio
FPCC	Fuel pool cooling and cleanup
FPQAP	Fire protection quality assurance program
FPS	Fire protection system
FPW	Fire protection - water system
FRI	Fuel reliability indicator
FRS	Floor response spectra
FSA	Fire subarea
FSAR	Final Safety Analysis Report
FWCF	Feedwater flow controller failure
FWL	Feedwater pump and drive lube oil system
FWP	Reactor feed pump seal and leakoff system
FWR	Feedwater pump recirculation system
FWS	Feedwater system
FZ	Fire zone

TABLE 1.11-1
(Sheet 6 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

GAF	Gain adjustment factor
GALL	Generic aging lessons learned
GDC	General Design Criterion
GE	General Electric Company
GE I&SE	GE Installation & Service Engineering
GE-LSTG	GE-Large Steam Turbine Generator
GE-NEO	GE-Nuclear Energy Operations
GEMS	Gaseous effluent monitoring system
GETAB	GE thermal analysis basis
GGNS	Grand Gulf Nuclear Station
GL	Generic Letter
GMH	Generator hydrogen and CO_2 system
GRBA	Growth rate based algorithm
GSI	Generic Safety Issue
GSN	Nitrogen system
GTAW	Gas tungsten arc weld
GTS	Standby gas treatment system
HAZ	Heat-affected zone
HCS	DBA hydrogen recombiner system
HCU	Hydraulic control unit
HDFM	Heavy density fill material
HDH	HP feedwater heater drains system
HDL	LP feedwater heater drains system
HELB	High-energy line break
HEM	Homogeneous equilibrium model
HEO	Human engineering observation
HEPA	High-efficiency particulate air/absolute (filter)
HEPCO	Hydro-Electric Power Commission of Ontario
HHL	High-high limit
HL	High limit
HPCI	High-pressure coolant injection
HPCS	High-pressure core spray
HPU	Hydraulic power unit
HRS	Hot reheat system
HSM	Horizontal storage module
HT	Tritiated gas
HTO	Tritiated oxide
HAZ	Heat-affected zone
HCS	DBA hydrogen recombiner system
HCU	Hydraulic control unit
HDFM	Heavy density fill material
HDH	HP feedwater heater drains system
HDL	LP feedwater heater drains system
HELB	High-energy line break

TABLE 1.11-1
(Sheet 7 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

HEM	Homogeneous equilibrium model
HEO	Human engineering observation
HEPA	High-efficiency particulate air/absolute (filter)
HEPCO	Hydro-Electric Power Commission of Ontario
HHL	High-high limit
HL	High limit
HPCI	High-pressure coolant injection
HPCS	High-pressure core spray
HPU	Hydraulic power unit
HRS	Hot reheat system
HSM	Horizontal storage module
HT	Tritiated gas
HTO	Tritiated oxide
HVAC	Heating, ventilating, and air conditioning
HVC	Control building air conditioning system
HVG	Glycol heating system
HVH	Hot water heating system
HVK	Control building chilled water system
HVP	Diesel generator building ventilation system
HVR	Reactor building ventilation system
HVW	Radwaste building ventilation system
HVY	Yard structures ventilation system
HWC	Hydrogen water chemistry system
HX	Heat exchanger
I&C	Instrumentation & control
IAC	Interim acceptance criteria (NRC)
IAS	Instrument air system
IBA	Intermediate break accident
ICC	Inadequate core cooling
ICF	Increased core flow
ICS	Reactor core isolation cooling system
ID	Inner diameter
IDC	Incident detection circuitry
IDS	Instrument data sheet
IE	Office of Inspection and Enforcement (NRC)
IED	Instrument and electrical drawing
IGSCC	Intergranular stress corrosion cracking
IJC	International Joint Commission
ILRT	Integrated leakage rate test
INPO	Institute of Nuclear Power Operations
IOP	Interim operating procedure
IPCEA	Insulated Power Cables Engineers Association
IPE	Individual plant examination
IRM	Intermediate range monitor
ISB	ISFSI storage building
ISC	Nuclear boiler instrumentation system
ISEG	Independent Safety Engineering Group

TABLE 1.11-1
(Sheet 8 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

ISFSI	Independent spent fuel storage installation
ISI	Inservice inspection
ISP	Integrated Surveillance Program
ISPT	Inservice pressure test
ISRM	International Society for Rock Mechanics
IST	Inservice testing
JAERI	Japanese Atomic Energy Research Institute
KTG	Karlstein
KWU	Kraftwerk Union
LCO	Limiting condition of operation
LCR	Logarithm of the count rate
LCS	Leakage control system
LDS	Leak detection system
LEFM	Leading edge flow meter
LER	Licensee Event Report
LFC	Loaded fuel cell
LFMG	Low-frequency motor generator
LFWH	Loss of feedwater heating
LGS	Limerick Generating Station
LHGR	Linear heat generation rate
LL	Low limit
LLL	Low-low limit
LLS	Low-low set
LMS	Containment leakage monitoring system
LOCA	Loss-of-coolant accident
LOFW	Loss of feedwater
LOOP	Loss of offsite power
LOS	Turbine generator oil conditioner and storage system
LPAP	Low power alarm point
LPCI	Low-pressure coolant injection
LPCS	Low-pressure core spray
LPDS	Loose parts detection system
LPEAC	Loose part event analysis computer
LPMS	Loose parts monitoring system
LPRM	Local power range monitor
LPSP	Low power setpoint
LPZ	Low population zone
LRA	License renewal application
LRBPF	Load rejection with bypass failure
LSA	Low specific activity

TABLE 1.11-1
(Sheet 9 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

LSCS	LaSalle County Station
LSD	Lake survey datum (of 1935)
LSMT	Lowest service metal temperature
LSSS	Limiting safety system setting
LTC	Load tap changing (mechanism)
LTM	Low-trajectory missile
LUFC	Loaded uncontrolled fuel cell
LWR	Light-water reactor
LWS	Radioactive liquid waste system
M&TE	Measuring and testing equipment
MAPLHGR	Maximum average planar linear heat generation rate
MBA	Misplaced bundle accident
M/CC	Maintenance and calibration communication (system)
MCC	Motor control center
MCPR	Minimum critical power ratio
MDAS	Meteorological data acquisition system
MDR	Maximum decay ratio
MELLLA	Maximum extended load line limit analysis
MELLLA+	Maximum extended load line limit analysis Plus
MELLLR	Maximum extended load line limit region
MG	Motor generator
MLD	Mean low water datum
MLHGR	Maximum linear heat generation rate
MMI	Modified Mercalli intensity
MOI	Method of images
MOV	Motor-operated valve
MPC	Maximum permissible concentration
MSF	Modified shape function
MSI	Main steam line isolation valve seal system
MSIV	Main steam isolation valve
MSIVF	Main steam isolation valve closure with flux scram
MSIV-LCS	Main steam isolation valve-leakage control system
MSL	Main steam line
msl	Mean sea level
MSLB	Main steam line break
MSR	Moisture-separator reheater
MSS	Main steam system
MTBE	Mean time between events
MTV	Mechanical trip valve
MWL	Maximum working load
MWR	Maintenance Work Request
MWS	Makeup water system

TABLE 1.11-1
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ABBREVIATIONS AND ACRONYMS USED IN USAR

NB	Nuclear boiler
NBR	Nuclear boiler rated (power)
NDE	Nondestructive examination
NDL	Nuclear data link
NDT	Nil ductility transition
NDT	Nondestructive testing
NDTT	Nil ductility transition temperature
NED	Nuclear energy division (GE)
NEG	GE Nuclear Energy Group
NEIL	Nuclear Electric Insurance Limited
NEMA	National Electrical Manufacturers Association
NFP	NUTMEG fuel preserve
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
NIST	National Institute of Standards and Technology
NMCA	Noble metal chemical addition
NMPC	Niagara Mohawk Power Corporation
NMPNS	Nine Mile Point Nuclear Station
NMS	Neutron monitoring system
NOAA	National Oceanic and Atmospheric Administration
NPCC	Northeast Power Pool Coordination Council
NPRDS	Nuclear plant reliability data system
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission
NRV	Nonreturn valve
NSOA	Nuclear safety operational analysis
NSRB	Nuclear Safety Review Board
NSS	Nonnuclear safety
NSSS	Nuclear steam supply system
NS^4	Nuclear steam supply shutoff system
NUMAC	Nuclear measurement analysis and control
NUMAC RWM	Nuclear measurement analysis and control rod worth minimizer
NVLAP	National Voluntary Laboratory Accreditation Program
NWS	National Weather Service
NYPA	New York Power Authority
NYPP	New York Power Pool
NYSEG	New York State Electric & Gas
NYSERDA	New York State Energy and Resource Development Agency
OBE	Operating basis earthquake
OCCWS	Open-cycle cooling water system
OEA	Operating experience assessment

TABLE 1.11-1
(Sheet 11 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

OFG	Offgas system
OFI	Oxygen feedwater injection
OFS	Orificed fuel support
OJT	On-the-job training
OL	Operating license
OLMCPR	Operating limit minimum critical power ratio
OLTP	Original licensed thermal power
ONI	On-line noble metal injection
OOS	Out of service
OPRM	Oscillation power range monitor
ORE	Occupational radiation exposures
OSC	Operational Support Center
OSHA	Occupational Safety and Health Administration
OT	Operational transient
PA	Public address (system)
PAM	Post-accident monitoring
PASS	Post-accident sampling system
PBA	Period based algorithm
PCI	Pellet-cladding interaction
PCIOMR	Preconditioning cladding interim operating management recommendation
PCRVICS	Primary containment and reactor vessel isolation control system
PCS	Process computer system
PCT	Peak cladding temperature
p.f.	Power factor
PGCC	Power generating control center
P&ID	Piping and instrumentation diagram
PIU	Process interface unit
PLSMT	Permissible lowest service metal temperature
PLU	Power load unbalance
PM	Preventive maintenance
PMF	Probable maximum flood
PMP	Probable maximum precipitation
PMS	Performance monitoring system
PMS	Probable maximum surge
PMW	Probable maximum wind
PMWS	Probable maximum windstorm
PORC	Plant Operations Review Committee
PORV	Power-operated relief valve
PP/PA	Page party/public address (system)
PQL	Product quality checklist
PRA	Probabilistic Risk Assessment
PRM	Power range monitor
PRMS	Process radiation monitoring system

TABLE 1.11-1
(Sheet 12 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

PRNM	Power range neutron monitor
PSAM	Pool swell analytical model
PSAR	Preliminary Safety Analysis Report
PSD	Power spectrum density
PSTF	GE Pressure Suppression Test Facility
PSTG	Plant-specific technical guideline
P-T	Pressure-temperature
PT	Inservice pressure test
PTPO	Project test program objectives
PVC	Polyvinylchloride
PVS	Plant vent stack
PWR	Pressurized water reactor
QA	Quality assurance
QATR	Quality Assurance Topical Report
QC	Quality control
RAB	Restricted area boundary
RBCLCW	Reactor building closed loop cooling water (system)
RBM	Rod block monitor
RBPC	Reactor building polar crane
RCA	Radiologically-controlled area
RCIC	Reactor core isolation cooling
RCPB	Reactor coolant pressure boundary
RCS	Reactor coolant (recirculation) system
RCSCM	RHR containment spray cooling mode
RDAS	Remote data acquisition system
RDCS	Rod drive control system
RDS	Control rod drive hydraulic system
RFM	Radwaste fault movement
RFP	Reactor feed pump
RG	Regulatory Guide
RH	Relative humidity
RHR	Residual heat removal
RHS	Residual heat removal system
RMCS	Reactor manual control system
RMS	Radiation monitoring system
RMS	Root mean square
RO	Reactor Operator
RPC	Rod pattern controller
RPIS	Rod position information system
RPS	Reactor protection (trip) system
RPT	Recirculation pump trip

TABLE 1.11-1
(Sheet 13 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

RPV	Reactor pressure vessel
RRCS	Redundant reactivity control system
RRS	Required response spectrum
RSCM	RHR reactor shutdown cooling mode
RSCS	Rod sequence control system
RSO	Reactor system outline
RSP	Remote shutdown panel
RSPCM	RHR suppression pool cooling mode
RSS	Remote shutdown system
RTD	Resistance temperature detector
RT_{NDT}	Reference temperature nil ductility transition
RTP	Rated thermal power
RTT	Response time testing
RWCU	Reactor water cleanup
RWE	Rod withdrawal error
RWM	Rod worth minimizer
RWP	Radiation work permit
SACF	Single active component failure
SAP	Site administrative procedure
SAR	Safety analysis report
SAS	Service air system
SBA	Small break accident
SBO	Station blackout
SCA	Single-channel analyzer
SCBA	Self-contained breathing apparatus
SCC	Stress corrosion cracking
SCEW	System component evaluation work
SDIV	Scram discharge instrument volume
SDM	Shutdown margin
SDV	Scram discharge volume
SEF	Single equipment failure
SER	Safety Evaluation Report
SFC	Spent fuel pool cooling and cleanup system
SGTS	Standby gas treatment system
SIL	Service Information Letter
SIM	Safety isolation module
SJAE	Steam jet air ejector
SLC	Standby liquid control
SLO	Single-loop operation
SLS	Standby liquid control system
SM	Shift Manager
SMAW	Shielded metal arc weld
SMSA	Standard metropolitan statistical area
SOE	Sequence of events
SOE	Single operator error

TABLE 1.11-1
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ABBREVIATIONS AND ACRONYMS USED IN USAR

SOF	Single operator failure
SOP	Special operating procedure
SORC	Station Operations Review Committee
SORV	Stuck-open relief valve
SOV	Solenoid-operated valve
SPC	Sound-powered communication (system)
SPC	Spent fuel pool cooling and cleanup system
SPCM	Suppression pool cooling mode
SPDS	Safety parameter display system
SPG	Substitute position generator
SPU	Stretch power uprate
SQRT	GE Seismic Qualification Review Team
SQUG	Seismic Qualification Utility Group
SRAB	Safety Review and Audit Board
SRCAS	Safety-related control air systems
SRDI	Safety-related display instrumentation
SRLR	Supplemental Reload Licensing Report
SRM	Security-related materials
SRM	Source range monitor
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SRR	Roof drainage system
SRSS	Square root of the sum of the squares
SRV	Safety/relief valve
SRVDL	Safety/relief valve discharge line
SS	Safe shutdown
SSA	Safe Shutdown Analysis
SSC	Structures, systems and components
SSDS	Safe shutdown system
SSE	Safe shutdown earthquake
SSES	Susquehanna Steam Electric Station
SSR	Reactor plant sampling system
SST	Turbine plant sampling system
SSW	Radwaste building sampling system
STA	Shift Technical Advisor
STP	Simulated thermal power
STRIDE	Standard Reactor Island Design
SVH	Feedwater heater relief vents and drains system
SVV	Main steam safety and relief valves vents & drains system
SW	Severe weather
SWEC	Stone & Webster Engineering Corporation
SWP	Service water system
SWR	Radwaste seal water system
SWT	Traveling screens wash and disposal system

TABLE 1.11-1
(Sheet 15 of 16)

ABBREVIATIONS AND ACRONYMS USED IN USAR

TAF	Top of active fuel
TBCLCW	Turbine building closed loop cooling water
TCV	Turbine control valve
TDH	Total developed head
TG	Turbine generator
TIP	Traversing in-core probe
TLAA	Time-Limited Aging Analyses
TLD	Thermoluminescent dosimeter
TLTA	Two-loop test apparatus
TME	Turbine generator gland seal and exhaust steam system
TMI	Three Mile Island
TNDT	Nil ductility transition temperature
TRM	Technical Requirements Manual
TRS	Test response spectrum
TSC	Technical Support Center
TSD	Training System Development
TSS	Temperature sensor/switch
TSVC	Turbine stop valve closure
TTBPF	Turbine trip with bypass failure
TVD	Test, vent and drain
UBC	Uniform Building Code
UFC	Uncontrolled fuel cell
UHS	Ultimate heat sink
UL	Underwriters' Laboratories Inc.
Unit 1	Nine Mile Point Nuclear Station - Unit 1
Unit 2	Nine Mile Point Nuclear Station - Unit 2
UPS	Uninterruptible power supply
URC	Ultrasonic resin cleaning
U.S.	United States
USAR	Updated Safety Analysis Report
USBM	U.S. Bureau of Mines
USE	Upper-shelf energy
USGS	U.S. Geological Survey
USI	Unresolved safety issue
USPHS	U.S. Public Health Service
USLS	U.S. Land Survey
UT	Ultrasonic testing
UTM	Universal Transverse Mercator
V&V	Verification and validation
VIP	Reactor vessel and internals
VWO	Valve wide open

TABLE 1.11-1
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ABBREVIATIONS AND ACRONYMS USED IN USAR

WCS	Reactor water cleanup system
WOS	Waste oil disposal system
WPMR	Whole pool multi-rack
WPPSS	Washington Public Power Supply System
WSLR	Within scope of license renewal
WSS	Radioactive solid waste system
WTH	Chemical feed - hypochlorite system
WTS	Water treating system
ZIP	Zinc injection passivation
ZPA	Zero period asymptote
4TCO	Temporary tall test tank-condensation oscillation

1.12 GENERIC LICENSING ISSUES

1.12.1 Introduction

This section contains the Unit 2 position regarding Generic Licensing Issues that have been identified from the dockets of other Operating License applicants. These generic issues were originally in the form of NRC questions to the license applicants, and dealt with TMI-related issues or Regulatory Guides which have undergone recent revision. The Unit 2 positions regarding the applicable TMI issues can be found in Section 1.10, and the Unit 2 positions regarding Regulatory Guide Degree of Compliance can be found in Section 1.8.

This section addresses Generic Licensing Issues that are applicable to Unit 2.

1.12.2 Licensing Issues

The Unit 2 position on Generic Licensing Issues is discussed in the following paragraphs. A list of these licensing issues is provided as follows:

Licensing Issue	Title
1	INTERNALLY-GENERATED MISSILES
2	CRD RETURN LINE REMOVAL
3	COMMITMENT TO PARTICIPATE IN SRV SURVEILLANCE PROGRAM
4	SRV PERFORMANCE TESTING
5	APPLICABILITY OF LIQUID FLOW-THROUGH SRV TEST
6	TRIP OF RECIRCULATION PUMPS TO MITIGATE ATWS
7	RCIC PUMP SUCTION SWITCHOVER
8	RCIC UNINTENTIONAL SHUTDOWN
9	ASSURANCE OF FILLED ECCS LINE
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61	TEMPERATURE DROP WITH FEEDWATER HEATER FAILURE
62	TEMPERATURE DROP WITH FEEDWATER HEATER FAILURE

LICENSING ISSUE: 1 - INTERNALLY-GENERATED MISSILES

Issue

Applicants have been requested to supply information to show that all safety-related systems and components within containment, including the containment, are protected from missiles.

Specifically, information has been requested concerning what is the valve size below which, if failure should occur in a high pressure system, damage to other components within the primary containment would be insignificant?

Position

Protection from missiles for all safety-related components within and including the containment is given in FSAR Section 3.5.

All valves, regardless of size, are incapable of becoming missiles based upon one or more of the following criteria:

1. Valve stems are provided with a backseat to prevent stem ejection should the thread fail.

2. Air-operated valve (AOV) or MOV items are effectively restrained by the valve operators.

3. Valves are constructed in accordance with the rules set forth in ASME Section III. Bonnets of pressure seal-type valves are prevented from becoming missiles because of the highly-conservative design of the retaining ring. For valves with bolted bonnets, the bonnets are prevented from becoming missiles by limiting the stress in the bolting and flange materials.

As indicated in Section 3.5.1.1.5 of the FSAR, recirculation pump failure will not result in the generation of missiles.

LICENSING ISSUE: 2 - CRD RETURN LINE REMOVAL

Issue

GE proposed a number of solutions to the problem of cracking in BWR control rod drive return line (CRDRL) nozzles. The NRC evaluated the proposed solutions and identified acceptable methods for performing the modifications in NUREG-0619.

One of the modifications involved total removal of the CRDRL and cutting and capping the CRDRL nozzle. Those utilities implementing this modification are required to evaluate the impact of the modification on the CRD system performance and submit performance data to conform with NUREG-0619.

Additionally, to ensure operability of the CRD system, the following items should be addressed.

1. This modification includes the addition of equalizing valves between the cooling water and exhaust water headers. (The purpose of these valves is to provide the means whereby the exhaust header pressure can be restored to that of the reactor vessel, as required under certain conditions, without subjecting the -121 HCU solenoid valves to a continuous reverse flow.) There is a concern that this equalization function might fail, resulting in a large pressure differential across the drive(s), leading to excessive drive speed and possible drive damage. Show how your design prevents this, or modify it accordingly.

2. With this modification, water from the CRD system returned to the RPV will be via the drives. There is concern that in some plants this return water may pass through carbon steel (rather than stainless) lines, deposit corrosion products in the vicinity of the ball check valve, and have a deleterious effect on operation of the ball check valve. Demonstrate how this will be prevented or prepare a plan for continued surveillance and maintenance of ball check valves and seats to prevent a possible common mode failure to scram of several CRDs from this source.

3. With the return line capped, the -121 HCU solenoid valves will be pressurized in reverse of the normal direction, resulting in reverse flow through the valve. It must be demonstrated that these valves are qualified for this mode of operation for the lifetime of the valve.

4. The capability of the CRD system to provide makeup water to the RPV should be demonstrated by flow testing. Flow measurement tests should be performed with both one and two pumps operating, including the system configuration outside the primary containment which will result in the maximum makeup flow to the RPV. This testing should demonstrate that the CRD system makeup capability is not significantly decreased by the proposed modifications. Procedures should be written to instruct the Operator how to establish the maximum makeup flow for both one- and two-pump operation, keeping in mind appropriate power and net positive suction head (NPSH) limitations.

5. With the return line capped, higher exhaust pressure during settling could be expected to result in slower drive settling. Provide evidence that expected drive settling margin has not decreased as a result of this modification.

6. During preoperational and startup testing, demonstrate proper operation of modified CRD components. Show that system performance potentially changed by the modification, e.g., equalizing valves, filters, scram times, settle function, has not been adversely affected.

<u>Position</u>

Unit 2 has implemented the GE recommendation to cut and cap the CRDRL nozzle without rerouting the CRDRL. This modification conforms to the conclusions of NUREG-0619. Unit 2 has incorporated the system modifications required in NUREG-0619 and will demonstrate satisfactory system operation in accordance with the criteria presented in NUREG-0619.

1. The equalizing valves (in the CRD system modification between the cooling water and exhaust water headers) offer a checking action to prevent possible drive damage.

2. Unit 2 system modifications incorporate stainless steel piping, hence the potential for crud formation and deposition is unchanged.

3. GE has 40-yr lifetime test information (cycle equivalent, with 10-yr rebuild points) on the -121 HCU solenoid valves. Results indicate no degradation of the valve functions with reverse flow.

4. The capability of the CRD system to provide makeup water to the RPV has been analytically demonstrated by GE. NUREG-0619 recommended the verification of the calculated flow rate to ensure that this system is capable of maintaining reactor vessel water level after scram. Due to the following reasons, Unit 2 need not demonstrate RPV makeup flow by test.

   a. Unit 2 employs post-TMI ECCS modifications. Use of CRD makeup flow is not a design requirement for safe shutdown. The ECCS is designed to meet all regulatory criteria for emergency vessel makeup.

   b. Unit 2 has enhanced fire protection and divisional separation requirements, which will ensure that the control over the emergency systems is not lost.

4. Preoperational testing verifies the acceptability of actual CRD operating times. Routine surveillance tests, in accordance with the Technical Specifications, ensure continued acceptability of CRD performance.

5. Preoperational testing at Unit 2 project verifies the acceptability of the entire CRD system.

LICENSING ISSUE: 3 - COMMITMENT TO PARTICIPATE IN SRV SURVEILLANCE PROGRAM

Issue

Applicants have been requested to participate in a SRV surveillance program.

Position

Unit 2 will comply with this requirement by participating in the BWROG program.

LICENSING ISSUE: 4 - SRV PERFORMANCE TESTING

Issue

Recent event reports from operating BWRs have shown that multiple relief valve failures may occur from a common failure mode. Assurance should be demonstrated that the relief valve design is qualified and that the probability of several SRVs failing is low.

Position

In the past, BWRs used pilot-operated SRVs. The concern with multiple relief valve failure does not acknowledge the use of direct-acting, spring-loaded SRVs. With this design, the SRV is directly and automatically controlled by steam pressure on the main disk. Problems identified with pilot seats are not applicable.

A functional description for the Unit 2 Dikker SRV is provided in Section 5.2.2.4 of the FSAR.

To ensure the function and quality of the SRVs, the following tests have been performed:

1. The capacity of the safety valve component of the SRV has been certified by tests under supervision of the National Board of Boiler and Pressure Vessel Inspectors, using the Coefficient of Discharge Method in accordance with ASME Section III, Paragraph NB 7825.

2. The actuator component of the SRV (assembly of cylinder and solenoid valve block) has been subjected to an aging test program to qualify its design.

3. A completely assembled SRV has been subjected to a seismic test program to qualify its design.

4. A completely assembled SRV has been subjected to a life cycle test program to qualify the design.

   It has been demonstrated that the SRV assembly has sufficient design integrity to maintain its functional properties and structural dimensions within the requirements during and after 300 operations without maintenance.

5. It has been demonstrated that the SRV will operate as specified when used under the following conditions:

· Ramp speed	2 - 232 psi/s
· Ambient temperature	90 - 200°F
· Functional backpressure	15 - 45% of inlet pressure
· Air supply pressure	90 - 200 psig
· Supply voltage	106 - 138 V dc

The blowdown of the SRV is sensitive to the actual backpressure; blowdown will be adjusted as specified for each valve. All other SRV properties remain unchanged (within specification requirements) when the above conditions vary during operational use.

The main spring has been preaged to provide for a constant set pressure load for 5 operational years minimum (regardless of the number of operations), and the characteristic and internal friction of the subassembly have been measured to ensure the optimal condition and reliable operations of this essential safety valve part.

6. Each actuator is run in while subjected to simulation tests and each 50th actuator is life cycle tested to ensure (at random) the optimal condition and reliable operations of this essential relief valve part.

7. The completely assembled safety valve has been hydro tested, based on the design data (for inlet and outlet), and meets the requirements of ASME III NB 6000.

8. Each completely assembled SRV was subjected to an extensive full steam flow test program to make the necessary adjustments, to verify its specified performance, and to ensure its optimal condition and the reliability of its functions.

Additional steam and water discharge tests were performed in response to TMI Action Plan Item II.D.1. These tests verified

the adequacy of SRV operability under expected liquid discharge conditions. The test is described in Licensing Issue 5.

LICENSING ISSUE: 5 - APPLICABILITY OF LIQUID FLOW-THROUGH SRV TEST

Issue

The alternate shutdown cooling condition is considered in the design evaluation of many BWR plants. This mode requires the flow of water through the SRVs and into the suppression pool. To take credit for this alternate mode of shutdown cooling, applicants have been requested to demonstrate the ability of the SRVs and their discharge piping to withstand the resulting flow conditions.

Position

Unit 2, through the BWROG, participated in a generic BWR SRV test program to satisfy the requirements contained in TMI Action Plan Item II.D.1, as specified in NUREG-0737.

Item II.D.1 requires that "testing to qualify the reactor coolant system relief and safety valves under expected operating conditions and design basis transients and accidents" be conducted. The expected valve operating conditions were determined by analyses of accidents and anticipated operational occurrences referenced in RG 1.70, Revision 2. The conclusions of this analysis were transmitted to the NRC in a letter dated September 17, 1980, to R. H. Vollmer (NRC) from D. B. Waters (BWROG). The analysis was supplemented by presentations to the NRC on February 10 and March 10, 1981. It was concluded that testing was appropriate for the alternate shutdown cooling mode. This mode is an anticipated operating condition for Unit 2 and has been considered in its design analysis.

The objectives of the BWR test program were:

1. To demonstrate the operability of SRVs for alternate shutdown cooling conditions.

2. To measure the SRV discharge line response for alternate shutdown cooling conditions and to compare these loads with steam loads.

   The tests included the Dikkers type used at Unit 2.

The test results showed that all of the tested SRVs operated correctly for all steam and water discharge tests. The maximum SRV discharge piping response was significantly less for water discharge than for the high-pressure steam discharge condition for which the piping is designed. Therefore, the integrity of

the SRVs and related discharge piping for all expected transients and accident conditions has been demonstrated.

The final generic test results were submitted in a letter dated September 25, 1981, to D. G. Eisenhut (NRC) from T. J. Dente (BWROG), Transmittal of Valve Operability Test Report.

The aforementioned analysis and test described satisfy the requirements of NUREG-0737, Item II.D.1.

LICENSING ISSUE: 6 - TRIP OF RECIRCULATION PUMPS TO MITIGATE ATWS

Issue

Applicants have been requested to reperform the overpressure protection analysis to consider the effect of the ATWS recirculation pump trip (RPT).

Position

The A/E overpressure protection analysis for ASME III Class 2 piping, when submitted, will consider ATWS-RPT impact in demonstrating compliance with the ASME III Code.

The NSSS vendors' overpressure protection report for ASME III Class 1 piping, when submitted, will consider ATWS-RPT impact in demonstrating compliance with ASME III.

LICENSING ISSUE: 7 - RCIC PUMP SUCTION SWITCHOVER

Issue

Applicants have been requested to supply sufficient information to determine whether the RCIC pump suction must be automatically switched from the CST to the suppression pool in the event of a SSE and concomitant failure of the CST.

Position

Unit 2 will implement the NRC position outlined in NUREG-0737, Task II.K.3.22, to automatically transfer RCIC suction source from the CST to the suppression pool upon low CST water level. (Refer to FSAR Section 1.10, Task II.K.3.22.)

LICENSING ISSUE: 8 - RCIC UNINTENTIONAL SHUTDOWN

Issue

Applicants have been requested to show how the design of the RCIC protection system prevents unintentional shutdown of the system,

when required, because of spurious ambient temperature signals from areas in and around the system (especially in the RCIC pump room).

Position

The temperature alarm setpoint is established by calculating a heat balance for the normal room environment, and then introducing the heat release caused by an alarm limit leak. Alarm temperature settings are verified to be appropriate during startup testing to reduce the potential for spurious system shutdowns.

LICENSING ISSUE: 9 - ASSURANCE OF FILLED ECCS LINE

Issue

The NRC staff has previously shown concern that pressure switches installed to ensure full HPCS, LPCS, and LPCI lines may be insufficient to detect voids at the top of the piping in these systems. Initiation of ECCS with a partially voided line could severely damage the system. Applicants have been requested to provide a design modification to ensure completely filled lines at all times. Identify the vertical locations of the presently installed pressure switches and the highest point in each system.

Position

The water leg pumps are continuously operated to keep the water legs filled. In essence, they deadhead against the static column of water without introducing air into the fluid system. Unit 2 utilizes ultrasonic level switches instead of pressure switches. These level switches monitor the fluid level in the standpipe from the discharge piping to the outer containment isolation valve. Entrapped air will collect in the standpipe; a change in density will be detected, and the level switch will initiate an alarm in the control room.

An exception to this arrangement is for the HPCS system which, due to its physical arrangement, may alternately, when the water leg pump is inoperable, rely on the static head of the CST to provide sufficient pressure to ensure the system piping is full to the outer isolation valve and system high-point vent. When the alternate method (CST static head) for the keep-fill function for HPCS is used, no safety-related alarm indication is provided to the Operator in the control room to provide indication of a deteriorative keep-fill function. This lack of safety-related alarm indication is compensated for by the increased surveillance frequency (Technical Specification Section 4.5.1.a.1) associated with high-point venting. The off-normal method of performing the keep-fill function for HPCS, as well as the increased Technical Specification surveillance frequency for high-point venting, is appropriately reflected in Station procedures.

LICENSING ISSUE: 10 - LEAKAGE TESTING OF REACTOR COOLANT SYSTEM ISOLATION VALVES

Issue

The check valves at the RCS/LPCS and RCS/LPCI boundaries perform an isolation function, aiding in protection of the low-pressure systems. It was recommended that these valves be classified category A/C in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, and that they be tested periodically. Applicants have been requested to provide a discussion of the leak tests and the acceptance criteria for these tests.

Position

The LPCS, HPCS, and RHR/LPCI injection check valves will be tested in accordance with ASME XI requirements. These valves will be classified as category A/C in accordance with the ASME XI in-service inspection (ISI) plan. This document will also include ASME XI categories for all isolation valves.

The leak testing of isolation valves and acceptance criteria for the tests are discussed in Sections 6.2.4 and 6.2.6 and Table 6.2-56 of the FSAR.

LICENSING ISSUE: 11 - CONTROL OF POST-LOCA LEAKAGE TO PROTECT ECCS AND PRESERVE SUPPRESSION POOL LEVEL

Issue

Applicants have been requested to demonstrate that passive failures, i.e., leakage from the first isolation valve outside the suppression pool, will be contained so that the suppression pool will not be drained nor redundant ECCS equipment flooded out.

Position

Unit 2 is designed to prevent a leak in one ECCS loop from affecting another and to prevent draining suppression pool water to an unacceptable level.

Unit 2 has separate watertight ECCS equipment rooms. Piping from the suppression pool to the ECCS pump rooms is located within dedicated flood troughs. Leakage from an ECCS pump is confined to an area associated with that ECCS loop; consequently, the redundant equipment in adjacent rooms is protected from flood. ECCS system components are Category I and designed to limit leakage. Further, each ECCS pump room is provided with leakage detection capabilities. If leakage is detected, the pump suction

isolation valve will be remote manually closed upon receipt of an alarm in the control room.

LICENSING ISSUE: 12 - ATWS

Issue

Applicants have been requested to implement plant modifications on a scheduled basis to conform with the NRC's final resolution of ATWS.

Position

The Unit 2 ATWS modifications are described in FSAR Sections 7.4, 7.6, 9.3.5, and 15.8 and include scram discharge volume (SDV) modifications, reactor coolant RPT, and automatic and manual SLCS operation. EOPs, based upon BWROG EPGs, are in place and Operators are trained to recognize ATWS events and take necessary mitigating actions. A review of the Unit 2 design has been performed, using NRC guidelines on ATWS, to establish additional modifications as required.

LICENSING ISSUE: 13 - LOW OR DEGRADED GRID VOLTAGE

Issue

Applicants have been requested to provide for a second level of undervoltage protection with time delay for the onsite power system.

Position

Unit 2 design includes a second set of undervoltage relays for protection of the onsite emergency power system against sustained degraded voltage conditions.

LICENSING ISSUE: 14 - TEST RESULTS FOR DIESEL GENERATORS

Issue

Applicants have been requested to provide test results for the standby diesel generators that include margin qualification tests to demonstrate some margin in excess of the design requirements with respect to the start and load capability of the diesel generators.

Position

The margin qualification test for the Division I and Division II standby diesel generators will be performed on site. The margin qualification test for the Division III standby diesel generator

(GE) has been addressed in GE HPCS diesel generator test report NEDO-10905-3. These plant-specific tests will be performed during the preoperational test phase.

LICENSING ISSUE: 15 - ADEQUACY OF THE 120-VAC RPS POWER SUPPLY

Issue

The RPS MG set design modification developed by GE is to be implemented for RPS power supply.

Position

The Unit 2 RPS power supply design includes the modification developed by GE.

LICENSING ISSUE: 16 - RELIABILITY OF DIESEL GENERATORS

Issue

Applicants have been requested to implement the appropriate recommendations of NUREG/CR-0660 that are applicable to the onsite emergency diesel generators.

Position

Unit 2 design meets the appropriate recommendations of NUREG/CR-0660.

LICENSING ISSUE: 17 - PHYSICAL SEPARATION AND ELECTRICAL ISOLATION

Issue

Applicants have been requested to verify that Class 1E instrumentation does not adhere to adequate separation criteria, is qualified, and adheres to separation of Class 1E to non-Class 1E instrumentation.

Position

The Unit 2 design meets the requirements of RG 1.75 for physical separation and electrical isolation, except for those items identified in the Unit 2 Degree of Compliance Statement for RG 1.75 (FSAR Section 1.8).

LICENSING ISSUE: 18 - LOSS OF SAFETY FUNCTION RESET

Issue

Applicants have been requested to comply with IE Bulletin 80-06, "Engineered Safety Feature Reset Control." In particular, identify systems that do not remain in emergency mode upon reset of the actuation signal. Justify any deviations or propose design changes.

Position

The problem described in the subject bulletin involves resetting ESF systems by resetting the actuation signal alone. For Unit 2, upon actuation of an ESF signal, all components proceed to their safety position and are, in turn, held there through seal-in circuitry. Therefore, to reset an ESF, two distinct Operator actions are necessary: one to reset the actuation signal, and one to reset the component or system.

During preparation of the failure modes and effects analyses (FMEA), a review is performed of each safety-related system to verify that following a reset of the actuation signal, the equipment remains as is, i.e., in its safety mode of operation, until deliberate Operator action is taken to reset it.

Unit 2 complies with the requirements of IE Bulletin 80-06.

LICENSING ISSUE: 19 - RCIC CLASSIFICATION

Issue

The RCIC system should be classified safety grade.

Position

The RCIC system is a safety system that consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to occur. Refer to FSAR Section 5.4.6 for a description of the RCIC system and FSAR Table 3.2-1 for component classifications.

LICENSING ISSUE: 20 - SAFE SHUTDOWN DISPLAY

Issue

Applicants have been requested to ensure that the design of safe shutdown indication satisfies the requirements of IEEE-279-1971, Paragraph 4.10.

Position

Post-accident monitoring and safe shutdown instrumentation is designed in accordance with RG 1.75 and 1.89. Parameter selection is based on RG 1.97, as described in FSAR Section 1.8.

Refer to FSAR Section 1.10, Task II.F.1, for additional information.

LICENSING ISSUE: 21 - MSIV LEAKAGE CONTROL SYSTEM

Issue

Single failure to the MSIV leakage control system has been identified that could lead to possible failure of the system during testing or operation.

Position

A MSIV leakage control system is not employed at Unit 2; therefore, this item does not apply. See Section 1.8 for the Unit 2 position on RG 1.96.

LICENSING ISSUE: 22 - SURVEILLANCE LEAKAGE TESTING OF THE CONTAINMENT

Issue

The applicant must commit to perform a single high pressure test prior to fuel loading. Low pressure bypass tests must be performed at regular intervals after fuel load.

Position

Unit 2 will perform a single high pressure test prior to fuel loading. Subsequent testing is unnecessary and will not be performed due to the unique containment design of Unit 2 (see FSAR Sections 3.8.1 and 6.2.1).

LICENSING ISSUE: 23 - POOL DYNAMIC LOCA AND SRV LOADS

Issue

The NRC has completed its review of the short-term program and developed acceptance criteria in NUREG-0802 and -0808. Applicants have been requested to commit to the acceptance criteria or justify any exceptions taken.

Position

Unit 2 meets the intent of the NUREGs and justifies exceptions taken to the acceptance criteria found in FSAR Appendix 6A.

LICENSING ISSUE: 24 - COMBUSTIBLE GAS CONTROL

Issue

The NRC has required applicants to adhere to the following conditions because of certain system characteristics:

a. If the containment pressure is above a certain pressure and the hydrogen concentration is a certain volume percent, the containment spray system must be actuated to reduce the containment pressure.

b. Following a LOCA, the recombiner system becomes an extension of the containment boundary. NRC requires applicants to demonstrate the leak-tight integrity of the recombiner system.

Response

a. Drywell and wetwell sprays will be manually actuated from the control room to reduce the pressure to an acceptable level. Following a LOCA, sprays will be manually actuated, as required, to provide gas mixing in the containment.

b. The recombiner system is normally isolated from the containment boundary. The automatic isolation signals to the isolation valves may be manually overridden to allow them to be opened if necessary for post-LOCA hydrogen control. The hydrogen control system (HCS) is a closed system outside the primary containment. Suction and discharge are to and from the primary containment. All piping remains within the secondary containment. Any leakage from the HCS will be processed by the SGTS prior to release to the environment.

LICENSING ISSUE: 25 - CONTAINMENT LEAKAGE TESTING

Issue

The applicant should provide information relating to containment leakage testing to show compliance with Appendix J.

Position

Containment leakage testing will be performed in accordance with Appendix J of 10CFR50. Testing methods and acceptance criteria are discussed in FSAR Section 6.2.

LICENSING ISSUE: 26 - BWR SCRAM DISCHARGE VOLUME

Issue

Describe the extent of conformance of the scram discharge system design to the criteria enumerated in the NRC SER, BWR Discharge System, dated December 1, 1980.

Position

The Unit 2 position is to implement modifications to the scram discharge system that will comply with the criteria identified in the SER of December 1, 1980.

LICENSING ISSUE: 27 - SAFE SHUTDOWN FOR FIRES AND REMOTE SHUTDOWN SYSTEM

Issue

10CFR50, Appendix R, Section III.L, Paragraph 2.d states: "The process monitoring function shall be capable of providing direct reading of the process variables necessary to perform and control the above functions." The above function of concern is stated in Paragraph 2.a: "The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions." The NRC would like all reactors to include the SRM indication on the remote shutdown system (RSS) panel to satisfy the requirement for monitoring.

Position

Adjacent to the Unit 2 RSS panel is a CRT and keyboard that is tied into the main plant computer, giving the Operator access to NMS information. The inclusion of a SRM indicator on the RSS panel would not provide additional information to the Operator. This design provides an alternative that meets the issue criteria.

LICENSING ISSUE: 28 - PROTECTION OF EQUIPMENT IN MAIN STEAM TUNNEL

Issue

It is required that the compartment in the auxiliary building between the containment and turbine building that houses the main steam lines and feedwater lines and their isolation valves be designed to consider the environmental effects (pressure, temperature, and 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 MSIVs and feedwater valves and

their operators, must be capable of operating in the environment resulting from the above crack.

Position

A subcompartment pressurization analysis was performed to evaluate the effects of a HELB in the main steam tunnel. Double-ended rupture breaks were postulated at various locations of the main steam tunnel area, as shown on Figure 3B-38, to determine the resulting accident environmental conditions. Data on mass and energy release from double-ended rupture of the main steam line and feedwater piping is provided in FSAR Appendix 3B. The results of this analysis indicate that the maximum pressure after the line break, even considering a double-ended rupture of the piping, would be less than the main steam tunnel design pressure. Thus, the structural integrity of the tunnel would not be jeopardized. Flooding consequences from an assumed crack equivalent to a single-ended rupture can also be accommodated by the plant design.

The feedwater isolation valves and MSIVs are designed for severe duty application with environmental effects more severe than the accident conditions derived from the postulated break. The qualification of the remaining safety-related equipment in steam tunnel will be demonstrated in FSAR Section 3.11.

LICENSING ISSUE: 29 - MSLIV BYPASS LEAKAGE RATE

Issue

Proposed Technical Specification limits for MSIVs that are greater than 11.5 scfh may significantly increase potential offsite doses. A reassessment of accident consequences is required to justify a higher limit.

Response

The Technical Specification values selected for the MSIV leakage rate do not exceed the 11.5 scfh limit and, when combined with the containment leakage, will assure that the radiological dose is in compliance with 10CFR100 and 10CFR50, Appendix A, GDC 19 requirements.

Values for the MSIV leakage rate have been changed to 24 scfh per Technical Specification amendment. Supporting analyses document compliance with 10CFR100 and 10CFR50, GDC 19.

LICENSING ISSUE: 30 - PREOPERATIONAL VIBRATION ASSURANCE PROGRAM

Issue

The applicant must commit to perform preoperational vibration testing.

Position

Unit 2 will comply with the above requirement (refer to FSAR Sections 3.9A.2 and 3.9B.2).

LICENSING ISSUE: 31 - RPV INTERNALS VIBRATION ASSESSMENT PROGRAM

Issue

The applicant must document their RPV internals testing.

Position

Unit 2 is a BWR-5 and documentation is provided by Licensing Topical Report NEDE-24057.

LICENSING ISSUE: 32 - DYNAMIC RESPONSE COMBINATION USING THE SRSS TECHNIQUE

Issue

The applicant should provide a description of the methodology used in the dynamic response analysis other than LOCA and SSE.

Response

The Unit 2 project complies with NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses."

LICENSING ISSUE: 33 - USE OF SRSS FOR MECHANICAL EQUIPMENT

Issue

The applicant must justify the use of SRSS methodology for mechanical equipment.

Position

Unit 2 complies with NUREG-0484, Revision 1.

LICENSING ISSUE: 34 - PUMP AND VALVE OPERABILITY ASSURANCE PROGRAM

Issue

The following question was posed to other applicants regarding analysis of piping subjected to SSE loads:

"When performing an analysis of a piping system subjected to SSE loads, and the system is found to remain below yield at all or substantially all points, state if the system is reanalyzed, using the lower OBE damping values of Table B-1 of FSAR Appendix B. If not, justify the use of the higher SSE damping values for a system which is below yield at all or nearly all points."

Position

Damping values from RG 1.61 (2 percent for nominal pipe sizes 12 in and under, and 3 percent for nominal pipe size greater than 12 in) are used in analysis of SSE loads. Maximum combined stresses due to static, seismic, and other dynamic loads are rarely significantly below yield stress for SSE. However, we do not reanalyze the piping system with lower damping values if maximum combined stresses are significantly below yield stress. This is justifiable in view of large safety margin inherent in seismic analysis.

LICENSING ISSUE: 35 - PUMP AND VALVE IN-SERVICE TESTING PROGRAM

Issue

The applicant must submit a proposed program for the in-service testing of pumps and valves as required by 10CFR50.55a(g).

Position

Unit 2 will comply with the above requirement. See Section 3.9A.6 for additional information regarding this issue.

LICENSING ISSUE: 36 - CRD SYSTEM RETURN LINE REMOVAL

Issue a

Deep cracks have been found in presently-operating BWRs in the feedwater nozzle blend radius, the nozzle bore, and in the interior blend radius of the CRD return nozzle.

1. Provide conclusive analytical and experimental proof that cracks such as these will not develop in the reactor vessel.

2. Submit a procedure for periodic in-service examination of the nozzle and bore surface areas from the inside surface or alternatively demonstrate the adequacy of conducting such an examination from the outside surface.

Position a

1. Testing and analyses which are applicable to the modified feedwater nozzle/sparger design were performed by GE. As a result, GE has designed an improved interference fit sparger (triple sleeve sparger). The design basis for the new sparger is included in NEDE-21821-02, Boiling Water Reactor Feedwater Nozzle/Sparger Final Report. Unit 2 has incorporated the improved interference fit sparger.

   The CRDRL has been eliminated from the Unit 2 design. The CRD return nozzle has been capped and will not be exposed to temperature transients that are different from reactor coolant transients. Therefore, the Unit 2 reactor vessel will not have this problem.

2. Preservice and in-service inspections of the feedwater and CRDRL nozzle will be performed in accordance with committed ASME Code requirements. Ultrasonic examination will be performed from the outside surface of the vessel using proven techniques.

<u>Issue b</u>

The following information is necessary to demonstrate that the feedwater inlet nozzle thermal sleeve/sparger design has been evaluated with consideration given to nozzle cracking due to thermal cycling:

1. The technical basis to assure the structural integrity of both the feedwater inlet nozzle and the sparger.

2. An evaluation of the feasibility of automated ultrasonic testing (UT) fixtures installed on all feedwater inlet nozzles with particular attention on examination of the nozzle bore region.

3. An evaluation of the feasibility of performing the internal surface examination by magnetic particle methods.

Your response should contain:

1. A description of the nozzle and sparger design including dimensions, materials of construction, and weld locations.

2. Description of analyses and test data, referencing date previously submitted to the staff where directly appropriate for Unit 2, if necessary.

3. Projected crack growth rates, stress levels, and usage factors for both the nozzle and the sparger should be described in detail.

4. Any plant modifications that are planned to reduce the feedwater to reactor water temperature differential during low-power operation.

5. Any instrumentation that will be installed in the reactor to verify the conclusions of the design analysis should be identified.

Several UT concepts and procedures have been used to examine the feedwater inlet nozzle regions in operating plants. Define the specific UT procedure that will be used at Unit 2. Discuss the influence of local in-service grindouts on crack detection on your UT method.

In addition, provide a description of the augmented ISI program to be implemented, including scheduled surface examination, UT, and verification of the leak-tight integrity of the thermal sleeve to safe end joint on all nozzles. The essential elements of an acceptable program are as follows:

<u>Augmented ISI Plan</u>

1. <u>Preservice Examination</u> - Preservice UT examination should include all nozzle inner radius, bore, and safe end regions. In addition, a preservice surface examination should be performed on the accessible regions of all nozzle inner radii.

2. <u>In-service Examination</u> - To confirm the continuing structural integrity, the following examinations should be performed:

    a. At each scheduled refueling outage, an external UT examination of all feedwater nozzle inner radii, bore, and safe end regions.

    b. After 50 startup/shutdown cycles but prior to 70 cycles, a surface examination of the accessible regions of all nozzle inner radii. The definition of startup/shutdown cycles and the procedure for liquid penetrant examination is contained in Report NUREG-0312, Interim Technical Report on BWR Feedwater and Control Rod Drive Return Line Nozzle Cracking.

    c. Subsequent surface examinations of the accessible region of all nozzle inner radii should be performed at the earlier of every other scheduled refueling outage, or at the scheduled refueling outage after 20 but prior to 40 startup/shutdown cycles after the last surface examination.

3. <u>Thermal Sleeve to Safe End Joint</u> - An examination method, such as a leak test, should be developed to

confirm the continuing structural and leak-tight integrity of the thermal sleeve to safe end joint.

Acceptance Standards

1. All UT indications evaluated to be cracks should be verified by appropriate surface examination and removed by local grinding.

2. All surface indications evaluated to be service-induced cracks should be removed by local grinding.

3. The UT inspection personnel should be required to demonstrate supplemental qualifications by either (i) past successful experience in locating and identifying cracks in BWR feedwater inlet nozzles or (ii) performing a qualification test on a full-size, unclad nozzle mockup.

Recording and Reporting Standards

Requirements for recording of indications and reporting of inspection results are contained in Report NUREG-0312.

Position b

The improved interference fit feedwater sparger design that is employed on Unit 2 is a generic design developed by GE. All construction details, test information, and analysis provided by NEDE-21821-A and discussed in NUREG-0619 are directly applicable to Unit 2.

Testing and analysis that are quantitatively applicable to the Unit 2 feedwater nozzle and sparger designs have been completed and are reported in NEDE-21821-A, February 1980 (GE Topical Report). Results show that the mechanisms which have caused cracking in operating BWRs are understood, and should not occur in the revised design being employed for Unit 2. The NRC has received and accepted the aforementioned topical report.

LICENSING ISSUE: 37 - INSPECTABILITY OF WELDED, FLUED HEADS

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 GE 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."

Position

The main steam line penetrations of Unit 2 are forged. They are not of a welded flued head design. This is addressed in FSAR Section 3.8.1.1.2 and Figure 3.8-10.

LICENSING ISSUE: 38 - EXPOSURE RESULTING FROM ACTUATION OF SRVs

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.

Position

The SRVs discharge in the primary containment, which is not normally accessible. Therefore, this issue is not considered to be applicable to Unit 2. An analysis of the activity of a discharge is described in FSAR Chapter 15.

LICENSING ISSUE: 39 - ROUTINE EXPOSURES INSIDE CONTAINMENT

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 RWCU rooms, SLC areas, TIP station, CRD HCU, and containment personnel lock. Provide maximum neutron and gamma exposure levels in these routinely-visited areas.

Position

All plant areas are categorized into radiation zones according to expected radiation levels and anticipated personnel occupancy with consideration given toward maintaining personnel exposure ALARA and within the standards of 10CFR20.

Radiation zone maps are provided in Section 12 of the Unit 2 FSAR. These zone maps include all routinely-visited areas in the reactor building. Zone radiation levels include contributions from any potential streaming through the drywell shield wall penetrations. Current design information is provided in Section 12.3.

LICENSING ISSUE: 40 - CONTROLLING RADIOACTIVITY DURING STEAM DRYER AND STEAM SEPARATOR REFUELING TRANSFER

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.

Response

During refueling at Unit 2, only the steam dryer is transferred from the reactor vessel to the internals storage pool. When the steam dryer is placed in the internals storage pool, a spray system is activated to keep the steam dryer wet while the refueling pools are being flooded. Once the refueling pools have been flooded, the steam separator is transferred underwater to the flooded internals storage pool.

In addition to the above procedures for maintaining the equipment wet, other methods employed to minimize personnel exposure to airborne radioactivity are administrative controls, including health physics surveillance, use of respiratory protection equipment, continuous ventilation purge of the refueling area, and containment access control during the transfer operation.

LICENSING ISSUE: 41 - SHIELDING OF SPENT FUEL TRANSFER TUBE AND CANAL

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-high radiation fields during fuel transfer.

Response

Unit 2 uses a Mark II containment design that requires no fuel transfer tube. During refueling at Unit 2, the fuel path between the reactor vessel and the spent fuel storage pool is protected by the fuel transfer shielding bridge which attenuates radiation that may pass into the drywell. Radiation doses will be maintained within the limits of 10CFR20.

LICENSING ISSUE: 42 - COMBINATION OF LOADS

Issue

For combining various dynamic loads, it is the NRC'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 NRC 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 Vessel Code Section III, Division 1, Subsection NE. However, the liner on 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 Boiler and Pressure Vessel 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.

Position

The absolute sum method of combining dynamic loads is used for the design of structures. The details of load combinations used in designing the structures are covered in FSAR Section 3.8.

The Unit 2 primary containment liner is evaluated for fatigue to the requirements of ASME Boiler and Pressure Vessel Code Section III, Division 1, Subsection NE.

LICENSING ISSUE: 43 - FLUID/STRUCTURE INTERACTION

Issue

The dynamic forcing functions for various loads have been established through testing on models that are generally more stiff than the actual structures to which the loads will be applied. By directly applying 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.

Position

This issue is not directly applicable to the Unit 2 Mark II containment. Since the Unit 2 containment is stiff in the suppression pool region and the dynamic forcing functions are conservatively defined, any interactive effect between the fluid mass and the structure is inherently included.

LICENSING ISSUE: 44 - LONG-TERM POST-LOCA OPERABILITY OF DEEP-DRAFT ECCS PUMPS

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.

Position

There are five safety-related deep-draft pumps utilized in the Unit 2 design. These are three RHR pumps, one LPCS pump, and one HPCS pump.

The inherent design features of the Byron Jackson ECCS pumps in Unit 2 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 24 ft, compared to the 30- to 160-ft pumps described in IE Bulletin 79-15. Also the pump assembly rigidity is enhanced by seismic rings between the assembly and the barrel. 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 ring seismic restraints act as

flow straighteners to suppress vortex formation. The pumps have high-precision, keyed, sleeve-type couplings.

A NRC letter dated December 6, 1983, requested additional information on methods used to qualify long-term operability of deep-draft pumps. The following is a description of the method used.

Long-term operability has been considered in the ECCS pump design. The ECCS pumps' effectiveness is evaluated by acceptance, qualification, and in-plant testing. Long-term operability is assured by preventive maintenance, inservice testing (IST) and surveillance, and vibration monitoring. Scheduled preventive maintenance consists of resistance readings of motor windings; lubrication of critical rotating components; general cleaning and inspection of rotating electrical equipment; and inspection, overhaul, alignment, and adjustment of impeller lift. IST measurements of each pump's differential pressure, flow rate, and vibration, as prescribed by the Code of record for the IST program for pumps and valves, as required by 10CFR50.55a, provide data for engineering analysis to identify performance changes or trends. In addition, vibration data bases, established during the preoperational/startup testing, are compared with functional-testing vibration data to monitor journal bearing wear and shaft whip.

IST and surveillance requirements are specified in Unit 2 Technical Specifications, surveillance procedures, and IST programs. Preventive maintenance and surveillance testing are scheduled at periodic intervals as the IST program test results indicate.

As part of the Unit 2 plant IST program, vibration measurements will be taken in accordance with the Code of record for the IST program for pumps and valves, as required by 10CFR50.55a. The data will be evaluated on a scheduled basis to predict potential bearing and journal failures and establish replacement schedules. Data will be available onsite for inspection.

Vibration limits shall be in accordance with the Code of record for the IST program for pumps and valves, as required by 10CFR50.55a.

Measurements will be performed using an IRD 360 or equivalent equipment, when the motor and pump are operated as a unit over the normal design range of pressure and flow. This limit is based on normal operation. Higher momentary increases may be acceptable during starting or at shutoff. This limit is not based on what the equipment can withstand. The equipment damage threshold is higher: close to 0.020 in, momentary and not sustained.

These deep-draft pumps, due to their relative shortness, demonstrate fewer of the problems associated with longer pumps.

The hydraulic design has been developed over the last 40 yr of experience in many applications.

The ECCS pumps contain design features to preclude failure of the impellers, impeller staking, shafts, bearings, wear rings, couplings, and stuffing boxes. The design includes safety factors (loading criteria) based on the expected pressures, temperatures, and loadings defined in the design specification. Lateral restraints are included in the pump to control deflections. Tolerances assuring alignment of the shaft and pumping elements are verified by design calculations. Motor shaft deflections within tolerance are predicted in a static seismic analysis and are verified by a qualification test of a similar motor. A dynamic analysis of the pump and motor is performed to determine resonances and predict loadings throughout the pump and motor.

Tests are performed on each pump delivered. The tests include head versus flow, NPSH, and vibration monitoring. The assembled pumps are checked for proper assembly and low friction by hand turning (rotating) the shaft. Each pump is run for a total of 100 hr during testing. A qualification test of a similar pump motor was performed. This data provides qualification of the Unit 2 pumps motors by a similarity analysis. During the First Ten-Year Interval, pump testing was performed in accordance with Section XI, 1983 Edition through the Summer 1983 Addenda; ASME OM-1987 through the OMa-1988 Addenda, Part 6; and the IST program plan. During the Second Ten-Year Interval and subsequent ten-year intervals, pump testing will be conducted in accordance with the requirements of 10CFR50.55a and the IST program plan.

LICENSING ISSUE: 45 - REPLACE HIGH DRYWELL PRESSURE INTERLOCK ON HPCS TRIP CIRCUITRY WITH LEVEL-8 TRIP TO PREVENT MAIN STEAM LINE FLOODING

Issue

Some designs included an interlock that prevented shutoff of the flow of the HPCS at high water level (8) in the reactor vessel when a high drywell pressure signal was present. Applicants were requested to remove this interlock.

Position

No such system interlock exists in Unit 2.

LICENSING ISSUE: 46 - ADDITIONAL LOCA BREAK SPECTRUM

Issue

The NRC staff has requested applicants to provide 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-sq ft area, using the small-break model analysis.

Position

The adequacy of the LOCA break spectrum is addressed in Section 6.3.3. Representative analyses done for the LaSalle plant supported by confirmatory plant-unique Appendix K calculations have been found acceptable to the NRC staff without further commitment.

LICENSING ISSUE: 47 - LOCA ANALYSES WITH CLOSURE OF THE RECIRCULATION FLOW CONTROL VALVE

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 has requested applicants to provide 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.

Position

Using the standard, approved licensing models and an assumed FCV closure rate of 11 percent per second, generic BWR/5 analyses showed an increase in the peak cladding temperature (PCT) of 45°F. The generic ECCS calculations applicable to Unit 2 yield a PCT that can accommodate this increase without violating the 2200°F limit of 10CFR50.46. It is expected that when the Unit 2-unique calculations are completed, the calculated PCT will also be able to accommodate the 45°F increase of FCV closure.

LICENSING ISSUE: 48 - ADEQUATE CORE COOLING MAINTAINED WITH LPCI DIVERSION

Issue

The NRC staff has asked applicants for a demonstration that adequate core cooling would be maintained if the flow of the LPCI were diverted to the wetwell and drywell sprays and to suppression pool cooling.

Position

This situation is addressed in Section 6.3. Sufficient margin exists in the PCT to accommodate the diversion of LPCI at 600 sec

into the transient. This demonstrates adequate core cooling. Further confirmation will be provided by the plant-unique ECCS analysis, which is scheduled for submittal the first quarter of 1985.

LICENSING ISSUE: 49 - RELIANCE ON NONSAFETY-GRADE EQUIPMENT IN THE ANALYSIS OF RECIRCULATION-PUMP SHAFT SEIZURE

Issue

The NRC has requested applicants to demonstrate that the limit for the minimum critical power ratio (MCPR) of 1.06 and the 10CFR100 limits are not violated when the analysis of this accident does not take credit for nonsafety-grade equipment.

Position

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 RPT 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.

LICENSING ISSUE: 50 - CLASSIFICATION OF LOAD REJECTION REJECTION WITHOUT BYPASS AND TURBINE TRIP WITHOUT BYPASS AND RECALCULATION OF MCPR

Issue

The NRC has requested applicants to recalculate the MCPR for the generator load rejection event, taking into consideration that 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.

Position

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. Load rejection without bypass is the limiting transient in determining the operating limit for the MCPR.

LICENSING ISSUE: 51 - ADEQUACY OF THE GEXL CORRELATION

Issue

The NRC has requested applicants to demonstrate that the GEXL correlation is to be applicable to the 8x8 design by comparison to applicable data.

Position

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 ensure shutdown capability.

LICENSING ISSUE: 52 - CORE THERMAL-HYDRAULIC STABILITY ANALYSES

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 GE'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.

Position

Sufficient documentation of an adequate stability margin for the Unit 2 first cycle has been provided. The stability margin analyses will be updated or redone as required for subsequent cycles of operation.

LICENSING ISSUE: 53 - POTENTIAL FOR TWO LOW-LOW SETPOINT VALVES TO OPEN

Issue

A single electrical failure in the low-low setpoint system hardware could cause the low and mid-low-low setpoint valves to open simultaneously or to be open concurrently. This would defeat the safety design basis. The design should be modified to correct this problem, or analyses should be presented to demonstrate that the present design is acceptable.

Position

Unit 2 does not incorporate the low-low set relief valve as an automatic function; therefore, this issue does not apply.

LICENSING ISSUE: 54 - ALLOWABLE LIMITS FOR BUCKLING OF THE REACTOR VESSEL SUPPORT SKIRT SUBJECTED TO FAULTED CONDITIONS

Issue

Provide the allowable limit for buckling for the reactor vessel support skirt subjected to faulted conditions.

Position

Buckling of the RPV support skirt for Unit 2 was evaluated 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 ASME Code Section III, Paragraph F-1370(c), faulted condition limit of 0.67 times the critical buckling strength for linear supports at temperature. The buckling stress of the skirt was calculated to be 0.467 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.

LICENSING ISSUE: 55 - NONCONSERVATISM IN THE MODELS FOR FUEL CLADDING SWELLING AND RUPTURE

Issue

The procedures proposed in NUREG-0630 introduce additional conservatism in the models for fuel cladding swelling and rupture during a LOCA. To assure the degree of swelling and incidence of rupture are not underestimated as required by Appendix K of 10CFR50.46, the NRC has required supplemental calculations to the current ECCS analyses. If the swelling is underestimated, the bundle cooling may be overestimated and the PCT may be nonconservative.

Position

When the Unit 2-unique ECCS calculations are prepared, the curve for perforation stress versus temperature will be modified for temperatures below 1,600°F and the then-current model technology will be utilized.

LICENSING ISSUE: 56 - WATER-SIDE CORROSION OF FUEL CLADDING DUE TO COPPER IN THE FEEDWATER

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.

Position

The Unit 2 feedwater heater tubes are made of stainless steel. The main condenser tubes are made with copper-bearing materials, but the condensate demineralizer system is designed to maintain adequate water quality with the copper-ion concentration below 2 ppb. As a supplement to the demineralizer, visual inspection will be used to detect fuel-cladding corrosion.

LICENSING ISSUE: 57 - BOUNDING ROD WORTH ANALYSIS

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 1 percent Δ-K. The NRC has requested applicants to provide the basis of this statement.

Position

Sensitivity studies presented in Response References 1 through 4 show large margins in peak enthalpy for rod worths below 1 percent Δ-K. This margin is sufficiently large that changes in Doppler coefficients, scram curves, reactivity insertion shape, etc., for rod worths below 1 percent Δ-K will not significantly reduce this margin. Therefore, if the compliance check shows the rod worth is below 1 percent Δ-K, the peak enthalpy for the control rod drop accident (CRDA) will be well below the 280 cal/gm limit. No unique bounding analysis is needed.

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).

LICENSING ISSUE: 58 - KUO SHENG IN-CORE INSTRUMENT-TUBE BREAK

Issue

During a Kuo Sheng 1 shutdown, an in-core instrument-tube break resulted in an extended LPCI, eventually causing fatigue failure of an in-core instrument tube and a subsequent 1-gpm leakage from the vessel.

Position

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 the Unit 2 design, the LPCI/LPCS is connected to the shroud above the top guide plate. Therefore, this issue is not applicable to Unit 2.

LICENSING ISSUE: 59 - HIGH-BURNUP FISSION GAS RELEASE

Issue

The NRC has requested an enhancement factor applied to calculated fission gas releases at burnups greater than 20,000 MWd/t because GE'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 PCT calculation will be nonconservative.

Position

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 October 22, 1981, letter from L. R. Rubenstein [NRC] to T. M. Novack [NRC], "General Electric ECCS Analysis at High Burnup").

LICENSING ISSUE: 60 - ADEQUATE TIME AVAILABLE FOR OPERATOR ACTION REQUIRED

Issue

In an applicant's analysis to evaluate a crack in the RHR line postulated to occur during normal shutdown cooling, Operator action was indicated to restore core cooling. The NRC staff has required applicants to show that adequate time is available for this Operator action.

Position

Should the RHR shutdown cooling line crack during a normal shutdown, a total reactor isolation will automatically occur. Subsequently, vessel water level will decrease to Level 2 and automatic initiation of HPCS will occur. HPCS will cycle on and off between Levels 2 and 8 until the Operator establishes an alternative water source.

For the case where HPCS is unavailable, representative analyses for similar BWR/5 plants have been performed to demonstrate that manual actuation of ADS would not be required before 20 to 30 min following the pipe crack to ensure adequate core cooling in accordance with the acceptance criteria of 10CFR50.46.

LICENSING ISSUE: 61 - TEMPERATURE DROP WITH FEEDWATER HEATER FAILURE

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 applicants to provide a justification for the smaller temperature drop or a reanalysis with a justified temperature decrease.

Position

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.

LICENSING ISSUE: 62 - ROD WITHDRAWAL TRANSIENT ANALYSIS

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.

Position

This issue is not applicable to Unit 2. In the BWR/5 design, the rod block monitor serves the functions of the rod withdrawal limiter in the BWR/6. The rod block monitor function does not vary with reactor power level; therefore, reactor power is not input to the system.

1.13 UNIT 2 POSITION ON UNRESOLVED SAFETY ISSUES

ISSUE: A-1 - WATER HAMMER

NRC Description

Water hammer (or steam hammer) incidents have occurred involving steam generator feedrings and piping, the RHR and RCIC systems, ECCS and containment spray, service water, feedwater, and steam lines. The incidents have been attributed to such causes as rapid condensation of steam pockets, steam-driven slugs of water, pump startup with partially empty lines, and rapid valve motion. Most of the damage reported has been relatively minor, involving pipe hangers and restraints; however, there have been several incidents which have resulted in piping and valve damage.

Schedule for NRC Resolution

This unresolved safety issue (USI) was resolved in March 1984 with the publication of NUREG-0927, "Evaluation of Water Hammer in Nuclear Power Plants - Technical Findings Relevant to Unresolved Safety Issue A-1." Also on March 15, 1984, the EDO sent the Commissioners SECY 84-119 titled, "Resolution of Unresolved Safety Issue A-1, Water Hammer."

Unit 2 Position

The main steam system, service water system, ECCS, and feedwater systems are designed to include such items as drain pots, sloped lines, properly located vents, and a system pressure pump to preclude the possibility of water hammer. The RCIC and RHR systems have been designed consistent with the recommendations of NUREG-0927 to minimize the potential for water hammer. Training programs in accordance with TMI Action Plan Item I.A.2.3 have also been incorporated. Unit 2 has developed proper filling and venting procedures as part of the Unit 2 design.

ISSUE: A-8 - BWR MARK II PRESSURE SUPPRESSION CONTAINMENT LONG-TERM PROGRAM

NRC Description

Additional loading conditions for the Mark II containment systems have been identified. These additional loads, which must be considered for the pressure suppression containment system design, result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA and from suppression pool response to SRV operation.

Schedule for NRC Resolution

This USI was resolved in August 1981 with the publication of NUREG-0808, "Mark II Containment Program Load Evaluation and

Acceptance Criteria," and SRP Section 6.2.1.1C. The requirement is that the 11 BWRs having the Mark II containment shall meet the requirements of GDC 16.

Unit 2 Position

The effect of additional loads on the containment systems is discussed in FSAR Appendix 6A, Design Assessment Report (DAR) for Hydrodynamic Loads. The design of Unit 2 incorporates the guidance of NUREG-0808, NUREG-0487 Supplements 1 and 2, and NUREG-0802, and is in full compliance with the requirements.

ISSUE: A-9 - ANTICIPATED TRANSIENTS WITHOUT SCRAM

NRC Description

During operation of a nuclear power plant, key parameters are monitored and used to actuate safety systems that initiate shutdown of the reactor (scram) upon receipt of an abnormal signal. There is concern that, given an operational transient, the system may not perform as designed and a scram may not occur. This could potentially result in fuel melt with the subsequent release of radioactive fission products.

Schedule for NRC Resolution

This USI was resolved in June 1984 with the publication of a final rule (10CFR50.62) to require improvements in plants to reduce the likelihood of failure of the RPS to shut down the reactor following anticipated transients, and to mitigate the consequences of an ATWS event.

Unit 2 Position

The Unit 2 ATWS modifications are described in FSAR Section 15.8 and include scram discharge volume modifications, reactor coolant RPT, and manual SLCS operation. Emergency procedures are established and Operators are trained to recognize ATWS events and take necessary mitigating actions.

ISSUE: A-10 - BWR NOZZLE CRACKING

NRC Description

During recent inspections of operating BWRs, cracking has been discovered in the feedwater nozzle and the CRD hydraulic return line nozzle. This cracking, initiated by high cycle fatigue, is caused by fluctuating water temperature. Further crack propagation is due to the thermal cycles associated with plant startup and shutdown.

Schedule for NRC Resolution

This USI was resolved in November 1980 with the publication of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking."

Unit 2 Position

Unit 2 incorporates an improved interference fit feedwater nozzle/sparger design developed by GE. Testing and analysis that are quantitatively applicable to the Unit 2 feedwater nozzle and sparger designs have been completed and are reported in NEDE-21821-A, February 1980 (GE Topical Report). Results show that the mechanisms which have caused cracking in operating BWRs are understood and should not occur in the revised design being employed for Unit 2. The NRC has received and accepted the aforementioned topical report.

In conformance to the conclusions of NUREG-0619, the CRD return lines have been eliminated from the Unit 2 design. The CRD return nozzles have been capped and will not be exposed to temperature transients that are different from reactor coolant transients.

ISSUE: A-11 - REACTOR VESSEL MATERIALS TOUGHNESS

NRC Description

The design of nuclear facilities does not provide protection against fracture of a reactor vessel. Prevention of reactor vessel failure depends primarily on maintaining the reactor vessel material fracture toughness at levels at which it will resist brittle fracture. Present reactor vessel materials offer adequate vessel fracture toughness. However, as plants accumulate more and more service time, neutron irradiation reduces the material fracture toughness and thus the safety margins.

Schedule for NRC Resolution

This USI was resolved in October 1982 with the publication of NUREG-0744, "Pressure Vessel Material Fracture Toughness." NUREG-0744 was issued by GL 82-26 and provided only a methodology to satisfy the requirements of 10CFR50 Appendix G. No licensee response to GL 82-26 was required.

Unit 2 Position

Unit 2 is in compliance with NUREG-0744 and 10CFR50 Appendix G, as described by FSAR Appendix 5A and Section 5.3.

ISSUE: A-17 - SYSTEM INTERACTIONS IN NUCLEAR POWER PLANTS

NRC Description

The NRC review and evaluation of plant systems is performed in accordance with the SRP, which is organized either on a system-by-system basis or by engineering disciplines. Similarly, the design of plant systems is accomplished by groups of engineers and scientists organized into their disciplines. Therefore, a concern exists that adequate considerations are not given to the potential for adverse systems interactions, particularly where this may adversely affect the presumed redundancy and independence of safety systems.

Schedule for NRC Resolution

GL 89-18, dated September 6, 1989, was sent to all power reactor licensees and constitutes the resolution of USI A-17. The generic letter did not require any licensee actions.

Unit 2 Position

Reviews for systems interactions are required for plant changes as part of Unit 2 procedures. In accordance with the guidance of GL 89-18, no further action is required.

ISSUE: A-24 - ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED ELECTRICAL EQUIPMENT

NRC Description

Accidents postulated for nuclear power plants could create severe environmental conditions such as temperature, pressure, humidity, radiation, chemical sprays, and submergence both inside and outside the containment. In order to ensure that the electrical equipment in safety systems will perform their intended function, it is required that such equipment be qualified to perform in the environment associated with an accident.

Schedule for NRC Resolution

This USI was resolved in July 1981 with the publication of NUREG-0588, Revision 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." Part I of the report is the original NUREG-0588 that was issued for comment; that report, in conjunction with the Division of Operating Reactor (DOR) Guidelines, was endorsed by a Commission Memorandum and Order as the interim position on this subject until "final" positions were established in rulemaking. On January 21, 1983, the Commission Memorandum and Order was the interim position on this subject until "final" positions were established in rulemaking. On January 21, 1983, the Commission amended 10CFR50.49 (the rule), effective February 22, 1983, to codify existing qualification methods in national standards, regulatory guides, and certain NRC publications, including NUREG-0588.

Unit 2 Position

Environmental qualification of Class 1E equipment located in harsh environments meets or exceeds the requirements for Category II qualification in accordance with NUREG-0588, including the guidance provided for incorporation of IEEE-323. The harsh environment qualification program is addressed in the Environmental Qualification Program Basis Document (EQPBD).

ISSUE: A-31 - RESIDUAL HEAT REMOVAL REQUIREMENTS

NRC Description

It is essential that a power plant be able to go from hot standby to cold shutdown condition under accident conditions. RHR systems normally are used for this function. The RHR system begins to operate when the reactor coolant pressure and temperature are substantially lower than their hot standby condition values.

Schedule for NRC Resolution

This USI was resolved in May 1978 with the publication of SRP Section 5.4.7. Only those plants expected to receive an operating license after January 1, 1979, were affected by this resolution. The USI involved establishment of criteria for the design and operation of systems necessary to take a power reactor from normal operating conditions to cold shutdown.

Unit 2 Position

Unit 2 is in compliance with the requirements of SRP Section 5.4.7 and RG 1.139, as described by FSAR Sections 1.8, 1.9, 5.4.7, and 6.3. In FSAR Section 1.8, Unit 2 takes exception to RG 1.139, pertaining to system redundancy, by justifying system performance assuming a single failure with limited Operator action outside of the control room, or by establishing an alternate shutdown cooling path.

ISSUE: A-36 - CONTROL OF HEAVY LOADS NEAR SPENT FUEL

NRC Description

Heavy loads may be handled in several plant areas as a result of normal operation, maintenance, and refueling activities. If these loads were to drop in certain locations in the plant, they might impact spent fuel, fuel in the core, or equipment required to achieve safe shutdown and decay heat removal. Such impacts could lead to radioactive releases, loss of capacity to achieve safe shutdown, or even accidental criticality if the fuel was of sufficient enrichment.

Schedule for NRC Resolution

This USI was resolved in July 1980 with the publication of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," and SRP Section 9.1.5.

Unit 2 Position

NUREG-0612 has been evaluated and a report entitled, "The Control of Heavy Loads at Nine Mile Point Unit 2," was incorporated into the FSAR (Appendix 9C).

ISSUE: A-39 - SRV POOL DYNAMIC LOADS

NRC Description

Operation of BWR primary system pressure relief valves can result in hydrodynamic loads or the suppression pool retaining structures or structures located within the pool. These loads result from:

1. Initial vent clearing of a relief valve pipe.

2. Steam quenching due to locally high pool temperature. (See also USI A-8.)

Schedule for NRC Resolution

This USI was resolved with the publication of SRP Section 6.2.1.1.C in October 1982. In addition, NUREG-0763, -0783 and -0802 were issued for Mark I, Mark II, and Mark III containments, respectively.

Unit 2 Position

The effect of hydrodynamic loads resulting from SRV operation is discussed in FSAR Appendix 6A, Design Assessment Report for Hydrodynamic Loads. The design of Unit 2 (Mark II containment) reflects the guidance contained in NUREG-0783 and, therefore, meets the requirements.

ISSUE: A-40 - SEISMIC DESIGN CRITERIA

NRC Description

This issue was initiated to identify and quantify the conservatism inherent in a seismic design sequence that is consistent with current NRC criteria. The two major phases of the tasks are Phase I, which deals with seismic response of structures, systems, and components; and Phase II, which is concerned with the definition of seismic input to analytical models.

Schedule for NRC Resolution

The staff has resolved USI A-40 as documented in NUREG/CR-5347, "Recommendations for Resolution of Public Comments on USI A-40," issued in June 1989, and NUREG-1233, "Regulatory Analysis for USI A-40," issued in September 1989.

Unit 2 Position

Unit 2 seismic design is developed in accordance with RG 1.60 and 1.61 and is described in FSAR Section 3.7A and 3.7B.

ISSUE: A-42 - PIPE CRACKS IN BOILER WATER REACTORS

NRC Description

Pipe cracks in BWRs have been observed in the heat-affected zones (HAZ) of welds that join austenitic stainless steel piping. This cracking is recognized to be intergranular stress corrosion cracking (IGSCC) of the austenitic stainless steel components that have been made susceptible to this failure mode by being sensitized either by welding or post-weld heat treatment.

Schedule for NRC Resolution

This USI was resolved in February 1981 with the publication of NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping." That NUREG document was issued to all holders of BWR operating licenses or construction permits and to all applicants for BWR operating licenses.

The long-term resolution of IGSCC in BWR piping (including the scope of USI A-42) was provided in NUREG-0313, Revision 2, which was transmitted to all holders of BWR operating licenses via GL 88-01.

Unit 2 Position

Materials for Unit 2 have been selected to minimize the possibility of IGSCC. Additionally, the intent of the requirements of RG 1.44 to control "the application and processing of stainless steel to avoid severe sensitization that could lead to stress corrosion cracking" has been met. Examination of IGSCC-susceptible material is described in FSAR Section 5.2.3.4.1 and is in compliance with NUREG-0313, Revision 1. The response to NUREG-0313, Revision 2, has been submitted to the NRC.

ISSUE: A-43 - CONTAINMENT EMERGENCY SUMP RELIABILITY

NRC Description

Following a postulated LOCA in a PWR, the water from the break will collect in the containment emergency sump and on the containment floor. Initially, during the course of the LOCA, the

borated water storage tank provides the necessary water for the operation of the ECCS and the containment spray system. Once the water in the tank reaches a predetermined low level, the emergency sump provides the necessary water for the ECCS and containment spray system operation. For BWRs, the concern is the reliability of the recirculation from the suppression pool.

Schedule for NRC Resolution

The resolution of this USI was presented to the Commission in October 1985 in SECY 85-349. NUREG-0897, Revision 1, "Containment Emergency Sump Performance," presents the results of the staff's technical findings. These findings established a need to revise current licensing guidance on these matters. RG 1.82 Revision 0 and SRP Section 6.2.2, "Containment Heat Removal Systems," were revised to reflect this new guidance. No licensee actions were required.

Unit 2 Position

The Unit 2 RHR suction lines from the suppression pool have been designed to provide a reliable, long-term water source for the RHR pumps, as discussed in FSAR Section 6.2.2. The potential loss of long-term containment cooling capability due to LOCA-generated debris has been assessed. Reviews for insulation blockage effects (GL 85-22) are required for plant changes as part of Unit 2 procedures. In accordance with the guidance of GL 89-21, no further action is required.

ISSUE: A-44 - STATION BLACKOUT

NRC Description

Station blackout (SBO) (that is, the loss of ac power from the offsite source and the onsite source) may be a relatively high probability event. SBO could cause an extended loss of decay heat removal capability which could then lead to some degree of core damage.

Schedule for NRC Resolution

This USI was resolved in June 1988 with the publication of a new rule (10CFR50.63) and RG 1.155.

Unit 2 Position

Unit 2 has provided their response to the NRC following the guidance of RG 1.155 and 10CFR50.63. Unit 2 followed the guidance of NUMARC 87-00 and the NRC found NUMARC 87-00 acceptable in meeting the requirements of RG 1.155. Special operating procedures (SOPs) are issued to comply with the SBO Rule, as described in Sections 1.8 and 8.3.1.5.

ISSUE: A-45 - SHUTDOWN DECAY HEAT REMOVAL REQUIREMENTS

NRC Description

The NRC staff believes that additional, alternative means of decay heat removal could substantially increase a nuclear plant's capability to deal with a broad spectrum of transients and could potentially yield a significant reduction in the overall risk to the public.

Schedule for NRC Resolution

USI A-45 was resolved by SECY 88-260, "Shutdown Decay Heat Removal Requirements (USI A-45)," issued September 13, 1988, without imposing any new licensing requirements other than the Individual Plant Examination (IPE). At the same time, the staff issued NUREG-1289, "Regulatory and Backfit Analysis: USI A-45." Since all of the significant USI A-45 results have been found to be highly plant specific, the Commission decided it was not appropriate to propose a single generic corrective action to be applied uniformly to all plants.

Unit 2 Position

See Issue A-31 for Unit 2 position.

This issue will be further evaluated under the IPE program which is expected to be completed by July 1992.

ISSUE: A-46 - SEISMIC QUALIFICATION OF EQUIPMENT IN OPERATING PLANTS

NRC Description

The seismic qualification of the equipment in operating plants must be reassessed to ensure the ability to bring the plant to a safe shutdown condition when subject to a seismic event. The margins of safety provided in the electrical and mechanical equipment important to safety of operating plants may vary considerably due to recent rapid development in seismic qualification criteria and methods.

Schedule for NRC Resolution

USI A-46 was resolved with the issuance of GL 87-02 on February 19, 1987, which endorsed the approach of using the seismic and test experience data proposed by the Seismic Qualification Utility Group (SQUG) and EPRI. This approach was endorsed by the Senior Seismic Review and Advisory Panel (SSRAP) and approved by the NRC staff.

Unit 2 Position

Seismic qualification and documentation procedures used for Class 1E equipment and/or systems meet the provisions of IEEE-344-1975,

as supplemented by RG 1.100 and discussed in FSAR Sections 3.10A and 3.10B.

ISSUE: A-47 - SAFETY IMPLICATIONS OF CONTROL SYSTEMS

NRC Description

A concern exists that failures or malfunctions of control systems may cause a postulated accident or transient to become more severe than analyzed. These failures and malfunctions can occur independently or as a result of the postulated accident or transient. The NRC, in this issue, is concerned about the control systems failures or malfunctions that occur after the postulated event initiation rather than the ones causing the event itself.

Schedule for NRC Resolution

This USI was resolved September 20, 1989, with the publication of GL 89-19. The generic letter made recommendations regarding plant design, procedures, Technical Specifications, and Operator training relating to reactor vessel overfill protection.

Unit 2 Position

Unit 2 control system failures studies have been performed as described in Appendix 7A, Sections 7A.3, 7A.4, and 7A.5. The results of these studies concluded that no failures would lead to consequences beyond what have been analyzed in Chapter 15.

The Unit 2 response to GL 89-19 (Letter NMP2L 1237 dated May 2, 1990) determined that:

1. The Unit 2 design provides adequate and reliable automatic overfill protection (reference BWROG report submitted to the NRC on April 2, 1990).

2. Existing operating procedures and Operator training ensure that Operators can mitigate reactor vessel overfill events.

3. Existing plant procedures and Technical Specifications include provisions for verifying the operability of the main feedwater overfill protection system.

Closeout of this issue is documented in NRC Safety Evaluation dated May 23, 1994.

ISSUE: A-48 - HYDROGEN CONTROL MEASURES AND EFFECTS OF HYDROGEN BURNS ON SAFETY EQUIPMENT

NRC Description

Postulated reactor accidents which result in a degraded or melted core can result in generation and release to the containment of large quantities of hydrogen. This USI will investigate means to predict the quantity and release rate of hydrogen following degraded core accidents, and various means to cope with large releases to the containment such as inerting of the containment or controlled burning. The potential effects of proposed hydrogen control measures on safety, including the effects of hydrogen burns on safety-related equipment, also will be investigated.

Schedule for NRC Resolution

The NRC staff concluded April 19, 1989, that USI A-48 is resolved, as stated in SECY 89-122.

Extensive research in this area has led to significant revision of the Commission's hydrogen control regulations given in 10CFR50.44, published December 2, 1981. This regulation required inerting of BWR Mark I and Mark II containments as a method for hydrogen control.

Unit 2 Position

Unit 2 has redundant external hydrogen recombiners with dedicated containment penetrations. These recombiners meet the single failure requirements of GDC 54 and 56 of Appendix A to 10CFR50. Unit 2 is operated with an inerted containment.